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BEFORE THE PUBLIC UTILITIIES COMMISSION OF
THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements	R.13-09-011 (Filed September 19, 2013)

SUBMISSION OF THE SUPPLY RESOURCE DEMAND RESPONSE INTEGRATION WORKING GROUP COMPLIANCE REPORT

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In compliance with Ordering Paragraph (OP) 4, f. (i) of Decision (D.) 14-12-024, San Diego Gas and Electric (SDG&E) hereby submits the Supply Resource Demand Response Integration Working Group Compliance Report on behalf of members of the Supply Resource Demand Response Integration Working Group. Representatives from the following organizations have participated in the Supply Resource Demand Response Integration Working Group: the California Large Energy Consumers Association, the California Independent System Operator Corporation, Olivine, Inc., Johnson Controls, Inc., EnerNOC, Inc., Southern California Edison Company (U338E), Pacific Gas and Electric Company (U39E), Comverge, Inc., and San Diego Gas and Electric Company (U902E).

Dated: June 30, 2015

Respectfully submitted

By <u>*/s/ Thomas R. Brill*</u>

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Supply Resource Demand Response Integration Working Group Compliance Report

June 30, 2015

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Report of the Supply Integration Working Group

Introduction

The Supply Integration Working Group presents this report to the California Public Utilities Commission (Commission or CPUC) pursuant to Ordering Paragraph 4(f)(i) of Decision 14-12-024, which states:

> i) Integration Working Group – Reports (filed as compliance reports) on the meetings held, the products developed, and the groups' successes and missteps; the mid-year report referred to in the charter, which is to include proposed changes, priorities and time-line, shall also be filed no later than June 30, 2015, as a compliance report;

Dr. Barbara R. Barkovich of Barkovich & Yap, Inc. (on behalf of the California Large Energy Consumers Association or CLECA) and Ali Miremadi of the California Independent System Operator (CAISO) co-chaired the working group. The Charter of the working group is included as Attachment 1. Its basic focus has been to identify perceived barriers to the integration of demand response (DR) into the energy and ancillary services markets of the CAISO and to propose possible solutions for overcoming or eliminating those barriers. The CAISO was actively involved in the working group's activities.

The group's active members are listed in Attachment 6 to this report and the members of each subgroup are listed in the subgroup reports. The report begins with a summary of the group's activities since it first met in August 2014. At that time, the group decided to focus on certain issue areas it deemed most critical. The subgroups working on those issue areas developed proposals for solutions included as Attachments 2-4. A summary of the issues and proposals is included in this report, along with the response of the CAISO to these proposals, and recommendations for future action by the Commission and/or CAISO. The telemetry and resource requirements issues have been well vetted and any further resolution will require actions by the Commission and by the CAISO. The working group believes that there is additional work to be done on the baseline issues and statistical sampling and the CAISO has encouraged it to continue its work and provide input to the CAISO's new Storage and Distributed Energy Resources Stakeholder Initiative. In the course of investigating the issue areas, participants identified additions concerns, outside of the scope of the initially-selected topics, whose resolution parties believe would also facilitate integration of more demand response into the CAISO's markets. The working group recommends that these additional issues be explored going forward through an appropriate, transparent procedural vehicle in which demand response providers, load serving entities, consumer representatives, the CAISO and the staff of the Commission can all participate. This could be either through the continuation of this working group or through a CAISO stakeholder initiative, or other process, as appropriate.[1] Some members of the working group support its continuation to address some of these additional issues. A motion requesting that the Supply Integration Working Group be continued until December 31, 2015, at a minimum to address the baseline and statistical sampling issues, will be filed in R. 13-09-011.

The working group focused on technical issues. At times policy issues surfaced which affected those technical issues. The report recognizes that these policy issues were outside of the scope of the group's activities, but has identified them so that others may address them at the Commission or the CAISO.

[1] FERC requires that changes in CAISO tariffs be examined through a stakeholder initiative prior to their being filed for approval at FERC.

Summary of Activities of the Supply Integration Working Group and Recommendations

As part of the Commission's demand response (DR) Order Instituting Rulemaking (OIR) (R. 13-09-011), testimony was served in May 2014 on an extensive array of issues related to DR policy matters. Limited hearings and workshops were held in June 2014. The testimony of several parties to the proceeding raised concerns about barriers to integration of DR into the energy and ancillary services markets of the California Independent System Operator (CAISO). These barriers were discovered by entities bidding DR on a limited basis into those markets. They were related to CAISO systems, processes and requirements. Part of one June 2014 workshop was devoted to the topic.

Because of the testimony and the workshops, it became apparent that these integration challenges were complex and technical and that addressing them would require close cooperation among the CAISO, Commission staff, and parties to the DR rulemaking. After hearings were suspended, negotiations were undertaken among the parties to the proceeding. These resulted in a Joint Proposal submitted by most parties in R. 13-09-011 to the Commission on August 4, 2014. Attached to the Joint Proposal was a set of proposed Working Groups in different topic areas. One of these was for a Supply Resource Demand Response Integration Working Group to address challenges discovered in integrating supply side DR into the CAISO's markets (Attachment 1). In Decision No. 14-12-024, the Commission formally endorsed the creation of an Integration Working Group (which is referred to as the Supply Integration Working Group or SIWG) to address the perceived barriers to integration and possible solutions and to report back to the Commission by June 30, 2015. [2]

Ali Miremadi of the CAISO and Dr. Barbara Barkovich became co-leaders of the SIWG. The first meeting of the SIWG was held on August 26, 2014 at the CAISO's offices in Folsom. While this meeting occurred before the Commission officially authorized the SIWG in its December decision, parties had concluded that it would be useful to identify and address the barriers as soon as possible, so that there would be time to develop possible solutions. Outreach was made to parties in the DR rulemaking to inform them of the meeting and its subject matter. After that time, Dr. Barkovich maintained a SIWG email list and updated it based on requests for participation.

During the initial meeting, the Working Group considered more than a dozen

[2] "Integration Working Group – Reports (filed as compliance reports) on the meetings held, the products developed, and the groups' successes and missteps; the mid-year report referred to in the charter, which is to include proposed changes, priorities and time-line, shall also be filed no later than June 30, 2015, as a compliance report" (D. 14-12-024, OP 4)

possible barriers to integration of DR into CAISO markets, beginning with those identified in the attachment to the Joint Proposal. They then ranked them based on impact. The following were the issue areas receiving the largest number of votes:

1) The CAISO's Demand Response System (DRS) and needed Application Programming Interfaces (API)
2) Telemetry Requirements for participation in CAISO markets
3) The need for additional Baseline methodologies for measurement and settlement
4) Resource aggregation rules and the 100 kW, one-Load Serving Entity (LSE), one Demand Response Provider (DRP), one sub-load aggregation point (subLAP) minimum resource requirement
5) The timing of access to revenue quality meter data (RQMD) for settlement

Issue Area 1: CAISO's Demand Response System

The CAISO stated that the development of the DRS should be kept out of the SIWG's scope and instead be managed through a CAISO stakeholder process by the CAISO project office. The CAISO later presented its concept for revising the DRS on September 23, 2014, at a workshop at the Commission in the Rule 24 proceeding (A. 14-06-001 et al.) It indicated that it would develop a new DR Registration System (DRRS) that would have four APIs: one each for locations, registration, baselines/performance and compliance calculations, and settlement. To provide an interim solution for integrating utility DR programs into its markets in 2015, the CAISO indicated it would immediately begin work on an interim solution for the Location API. The Phase 1 solution "went live" at the end of March 2015, although there have been some issues with its implementation, as discussed below under Other Issues. The formal CAISO stakeholder process for continued Phase 2 development of the DRRS was initiated through a customer partnership group (CPG) that began on 5/12/2015.

Issue Area 5: Timely Access to Revenue Quality Meter Data

The timing and access to RQMD was identified as a CPUC issue and delegated to the Rule 24 proceeding at the Commission. It was discussed at a workshop on October 9, was the subject of comments and briefing, and was addressed in D. 15-03-042.

Issue Areas 2-4

The remaining three issue areas, Issues 2-4, were assessed through subgroups under the SIWG: telemetry, baselines, and resource requirements. SIWG participants were invited to participate in each subgroup and each subgroup was assigned a CAISO staff member. Robert Anderson of Olivine headed the telemetry and resource requirement subgroups, with Ali Miremadi of the CAISO Operations Department as CAISO lead person for telemetry and John Goodin of the CAISO Policy staff as its lead person for the resource requirement subgroup. Wendell Miyaji of Comverge and Steven de Backer of Pacific Gas and Electric Company (PG&E) headed the baseline subgroup with Ali Miremadi as CAISO staff lead person. The subgroups met by conference call rather than in person. They explored each issue and discussed possible solutions. Each issue paper went through numerous revisions. Preliminary results were presented to the entire SIWG at a meeting at the Pacific Energy Center in San Francisco on October 29, 2014.

The subgroups continued to work on solutions. Their almost-final results were presented to another meeting of the entire SIWG at the Pacific Energy Center on February 10, 2015. Also present were Commissioner Michel Florio, his advisor Matthew Tisdale, and various members of the staff of the CPUC's Energy Division. After the meeting, participants were asked to provide any additional feedback on the presentations. While no changes were proposed for the telemetry and resource requirement issue papers, a discussion of DR and storage led to a proposal for an additional baseline methodology, Meter Generator Output, to the baseline document, and this was incorporated into the final issue paper.

The final telemetry issue paper was delivered to the CAISO on February 20, 2015. The resource requirement issue paper was delivered on February 24, 2015. The final baseline issue paper was delivered on February 28, 2015. These issue papers are attached (Attachments 2-4).

While participants awaited the CAISO's response to the issue papers, one matter was identified in the resource requirements (aka load-serving entity or LSE) issue paper by the CAISO as a CPUC, and more generally a local regulatory authority, concern. Specifically, the CAISO's Demand Response Provider (DRP) Agreement requires DRPs to certify that any required bilateral agreements between the DRP and the LSE or other agreements required by the Local Regulatory Authority are fully executed. The CAISO has suggested that the Commission can mitigate this issue through its own actions and authority as discussed below.

Later sections in this report will summarize the subgroup issues and proposed solutions, full copies of which are attached as they were forwarded to the CAISO, followed by the CAISO response to these proposals. The CAISO responses were received on May 7, May 19, and June 19.

The CPUC decision directed that a report on the progress of the SIWG be provided to the Commission no later than June 30, 2015. This report is being submitted on June 30, 2015.

Proposed Action Items for the Commission:

The report identifies four action items for the Commission specifically analyzed by the working group that will facilitate integration of DR into the CAISO's markets. These are summarized here.

First, the working group recommends that, since the Commission, as a Local Regulatory Authority (LRA) under the CAISO's tariffs, does not require an agreement between a non-utility Demand Response Provider (DRP) and a Load-Serving Entity (LSE), it should inform the CAISO of this fact and ask the CAISO to not require such an agreement for customers of its jurisdictional LSEs to participate in the CAISO's markets.

Second, the working group recommends that the Commission send a letter to all of its jurisdictional LSEs that are not currently enrolled in the CAISO's demand response system (DRS), *i.e.*, any un-enrolled electric service providers (ESPs) and community choice aggregators (CCAs), advising them to enroll in the CAISO's DRS and subsequent DRRS. The working group also recommends that all new CPUC-jurisdictional LSEs be automatically enrolled in the CAISO's DRS and subsequent demand response registration system (DRRS) pursuant to formal written guidance from the Commission to the CAISO to do so. The working group notes that the Commission has limited jurisdiction over CCAs that does not include jurisdiction over DR matters. As such, the working group recommends that the Commission provide written advisement to all new CCAs that they should enroll with the CAISO's DRS and subsequent DRRS as part the Commission's response to the new CCA when the CPUC reviews the CCA's implementation plan. The working group believes this heightened awareness for new LSEs will help to mitigate the present issue of not all LSEs registering within the CAISO's DRS, limiting the ability of consumers to participate in wholesale DR. The Commission should also provide guidance to new ESPs to enroll with the CAISO DRS and subsequent DRRS as well.

Third, the working group recommends, and anticipates a petition to modify D. 14-12-024 to permit, that the working group continue its operations to address at a minimum ongoing issues related to baselines and statistical sampling and to provide related input to the CAISO for the development of its new DR systems and for its stakeholder initiative on Energy Storage and Distributed Energy Resources.

Fourth, the working group recommends that the Commission reconsider the issues associated with the default load adjustment and concerns about double payment to provide input to the CAISO as to whether the latter should propose to eliminate the default load adjustment in its tariff.

Fifth, the working group recommends that the Commission review the differences between its baseline calculations and those of the CAISO to determine whether these differences create inappropriately different settlement results for retail and wholesale DR.

Anticipated CAISO Actions:

The working group anticipates that the CAISO will:

- Address the creation of additional settlement baselines in its Energy Storage and Distributed Energy Resources stakeholder initiative during 2015, leading to adoption of new baselines, a FERC tariff filing, and implementation by early 2018, taking into account the recommendations of the continued activity of this working group on baseline and statistical sampling matters. In the meantime, the existing baselines will be used.

- Complete its registration API and revise its location API by mid-2016.

- Complete its APIs for baselines/performance and compliance calculations, and for settlements by the end of 2016 or early 2017.

- Complete the proposed changes in the Direct Telemetry Business Practice Manual by early 2016.

Other Issues For Resolution:

Other issues arose during the deliberations of the working group that were not substantially addressed. These are listed below. The Commission and the CAISO should determine the significance of these issues and decide how and where best to address them, with participation of all interested parties.

- baseline calculation differences between the Commission and the CAISO for customers with behind-the-meter storage and/or onsite generation participating in net energy metering.

- baseline calculation and submetering issues as they relate to implementation of the proposed Meter Generator Output baseline. Submetering per se is an issue that needs to be resolved by the Commission in a timely manner to make the baseline workable.

- meter data accuracy tolerances for settlement quality meter data (SQMD), scheduling coordinator burden, and processes for data changes and payment of penalties for changes after T+48.

- cost-effective options for telemetry, particularly for mass market DR. Otherwise, large residential and potentially some commercial aggregations for proxy demand resources (PDR) will be limited to resources of less than 10 MW participating only in energy markets.

- coordination of decisions in the Rule 24/32 proceeding (A. 14-06-001 et al) and other relevant proceedings (such as utility applications to integrate their own DR), to address meter data requirements for participation in real-time and ancillary services markets with integration timelines and utility information systems requirements.

The working group also recommends that the Commission review the interactions among the efforts of this working group, the DR Auction Mechanism and Rule 24/32, which generally involve the integration of third party-aggregated DR. In addition, the utilities will need to develop requirements to integrate their own programs into the CAISO's markets. Appropriate time must be allotted for the regulatory processes required to fund these activities as well as to build, test and implement mass market integration solutions. The working group recommends that a roadmap be developed which includes all interdependencies for implementing its bifurcation policy goal for 2018.

Summary of Telemetry Issues and Proposed Solutions[3]

Uses of Telemetry

Telemetry is central to the CAISO's real-time systems. It is the means by which the CAISO determines the near-instantaneous status of the grid, which informs dispatch instructions to resources on the grid for real-time balancing of the system. Telemetry is used for 1) the Market Model, 2) real time visibility and situational awareness, and 3) as evidence of the CAISO's compliance with North American Electric Reliability Council/Western Electricity Reliability Council (NERC/WECC) Reliability Standards requirements.

The CAISO points to several NERC standards that require the CAISO to have a telemetry solution in place for resources. However, the expectations around the size of the resource and scan rate data are not explicitly spelled out. For this reason, each Independent System Operator/Regional Transmission Operator (ISO/RTO) has slight variations in the solution adopted for telemetry. In addition, WECC has a more stringent version of the BAL-002 for its region than the rest of NERC. The obligation to show documentation that contingency reserve obligations were met does not exist outside of the WECC region, giving other ISO/RTOs somewhat more flexibility regarding Ancillary Services telemetry than the CAISO.

BAL-005-0.2b

> R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for Area Control Error (ACE), Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

TOP-006-2

> **R1.** Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.
>
> **R6**. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if

[3] In order to advance the potential for achieving a consensus recommendation on reducing barriers to DR participation in the wholesale market related to telemetry, parties made concessions on positions that they would otherwise contest. Therefore, the positions reflected in this document are those of the working group and not of any individual participant.

applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

BAL-002-WECC

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

In addition, the North American Energy Standards Board (NAESB) published its recommendations for measurement and verification (M&V) methodologies for DR participation in wholesale markets. NAESB's M&V recommendations give system operators guidance as to the type of metering they can deploy for purposes of DR participation in wholesale markets, including telemetry and after-the-fact metering. NAESB's DR metering language describes the metering options and provides discretion to the operator. It does not mandate telemetry. However, to the extent the operator selects telemetry for energy or capacity products, it requires the interval be no larger than 5 minutes and accuracy to be within 3% for Capacity and Operating Reserve products. For after-the-fact metering, the meter data report interval shall be no larger than 1 hour. The exception is for DR resources providing regulation, in which case NAESB requires a scan rate not to exceed 6 seconds.

The CAISO telemetry requirements apply to DR resources with a capacity of 10 MW or greater that are not exempt under its tariff, to resources providing ancillary services, and to resources that are eligible intermittent resources unless the resources are exempt under its tariff. Reliability DR Resources (RDRR) are not required to have telemetry.

The telemetry requirement imposes a cost on the resource. Since DR is comprised of numerous, geographically-dispersed resources, the cost to obtain data from each location would be significantly greater than for a single generating unit at one location. While statistical sampling may reduce telemetry costs for dispersed resources, it has not yet been implemented commercially. Lower cost telemetry solutions, including software-based solutions, exist today; however, the per-site installation and maintenance costs of any solution can be substantial.

CAISO asked the working group to concentrate on the attribute of a telemetry solution that, if relaxed, would reduce the cost of implementing a telemetry requirement for DR resources, since CAISO considered a "no telemetry" proposal unlikely to be accepted. In response, the working group made two main proposals: one to reduce or eliminate the telemetry requirement for PDR resources that exclusively provide energy, and others to potentially ease implementation and operational costs associated with providing telemetry, when required. Paragraph 1 below is a proposal by the working group to CAISO that, if adopted, would eliminate the telemetry requirement if a certain threshold were met. Consistent with CAISO's request, the working group also identified the attributes that, if relaxed, would reduce the cost of a telemetry solution. These recommendations are presented in paragraphs 2, 3 and 4 below.

Issues Addressed by Subgroup

Possible Elimination of Telemetry Requirements (Proposal 1)

1. The telemetry requirement imposes costs. If telemetry were only required for DR resources with higher capacity levels or if the telemetry requirements were eliminated for energy-only DR resources, the cost burden upon DR aggregators/providers would be reduced. Thus, the subgroup asked the CAISO to consider whether the requirement for telemetry for an energy-only resource 10 MW or greater could be eliminated. In addition, the subgroup asked for CAISO to consider raising the threshold for the telemetry requirement from 10 MW to 50 MW for an energy-only resource with multiple locations. In some other ISO/RTOs, e.g., PJM, energy-only telemetry is not required for DR resources, and only after-the-fact information is provided for settlement purposes, avoiding this cost burden. Some of the other ISO/RTOs have more stringent telemetry requirements. The CAISO has indicated that WECC's requirements are more stringent than those of other ISO/RTOs. A select group of other ISO/RTO requirements is provided in Attachment 5.

Southern California Edison (SCE) has recommended that the Midwest ISO (MISO) Demand Response Resource (DRR) Type 1 resource be considered in California to integrate legacy DR programs that are currently administered by the California utilities. SCE's reason is that these programs are typically not capable of providing partial dispatch, and may not be cost effective to operate if required to implement telemetry (especially mass market programs). SCE believes that if a MISO DRR Type 1 or similar product were to be adopted in the CAISO market, it would be easier for more of the existing utility DR programs to participate in the wholesale market. MISO DRR Type 1 is a discrete dispatch product and, like RDRR, does not require telemetry. However, unlike RDRR, it can be discretely dispatched in both day ahead and real time markets. DRR Type 1 can be bid economically in the day-ahead market and, if awarded, it is awarded at full capacity. Unlike CAISO's RDRR product, DRR Type 1 can only self-schedule, which means it is not optimized in real time and it does not set the real time market price. Any proposal to add a new type of DR resource in the CAISO's market would require a CAISO stakeholder initiative and tariff changes. As noted later in this report, the CAISO is not supportive of expanding discrete dispatch options in its markets.

Reducing Cost of Telemetry Requirements (Proposals 2 through 5)

2. The CAISO currently requires DR resources with telemetry to provide data every minute. This creates an additional challenge and expense because utility meters cannot provide 1-minute data and at present cannot provide 5-minute data.[4] Reprogramming utility meters to provide such data and storing the data would be costly. One possible solution is the use of devices that are purchased by the DR aggregator/provider and installed by the utility to interface with customer meters that read customer usage at smaller intervals. One such device is called a KYZ pulse device. These devices can be programmed to read data at specific intervals, including every 1 or 5 minutes. For the same reasons as identified elsewhere herein, programming the KYZ pulse devices to gather usage readings every minute imposes additional costs (storage, E, M&V) and accuracy challenges.

Providing each customer with a KYZ pulse device, including installation and communication equipment, even for longer intervals, would still be costly on a per-site basis and can be cost-prohibitive for smaller customers. There are also costs and challenges to aggregating data from each resource to the resource registration level and then communicating that information to the CAISO. Even considering that, the subgroup proposed that the CAISO consider accepting 5-minute averaged reads for DR resources for Energy and Non-Spin Ancillary Services subject to certain data and time accuracy requirements, rather than 1-minute data, noting that this will reduce costs in some cases – but not others – based on the use of existing KYZ pulse device installations.

3. The CAISO's Direct Telemetry Business Practice Manual (BPM) requires telemetry data to be accurate to within +/-2%.[5] This is a challenging requirement for distributed resources for several reasons. As discussed above, in order to obtain data in intervals acceptable to CAISO, DR aggregators/providers have to provide additional measurement and communication equipment to each customer location. By the utility tariffs, retail meters must also be accurate to within +/-2%.

Secondly, meter information will be aggregated across multiple locations, as opposed to one reading from one facility. The KYZ pulse data device is not the source of revenue quality meter reads; the utility meter provides these data. It is possible to have a certain amount of acceptable tolerance between the utility meter and the KYZ pulse device. The utility meter will be measuring a different usage interval than the KYZ pulse device. All of the data that will be transmitted to the CAISO in real time (with approximate 5-minute latency) will not have been verified, edited or estimated (VEE'd) relative to approved methods. While VEE is not

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[4] The matter of utility meters providing 5-minute data is under consideration in A. 14-06-001 et al. However, the billing metering interval does not translate into an accessible interval for third party DRPs to provide real time telemetry.

[5] CAISO Direct Telemetry Business Practice Manual, Section 5.5.

required for telemetry by the CAISO, there is still some concern among DR aggregators/providers as to their ability to meet the telemetry accuracy requirements.

To address these concerns, the subgroup made recommendations about how data accuracy would be measured and tested. So long as the meter and/or device has been tested and found to be accurate within +/-2%, the DR aggregator/provider will have met its obligation.

4. The subgroup recommended that the requirements to provide telemetry data and for those data to meet accuracy requirements only apply during periods when the resource is in a dispatchable state, i.e. has the potential for energy dispatch, rather than on a 24x7 basis.

5. The subgroup raised certain technical questions about the wording of the CAISO's Direct Telemetry Business Practice Manual (BPM) and proposed clarifying changes.

CAISO Response:

The CAISO has rejected Proposal 1, partially because it felt that the issue of adjusting the 10 MW minimum telemetry resource threshold ought to be discussed as part of a formal CAISO stakeholder process, and not through an informal working group process. Additionally, the CAISO has advised the working group that it believes any change to increase the minimum threshold for telemetry is unlikely to occur. The CAISO has committed to change its BPM (for Energy Only) to reflect the working group proposed recommendations 2, 3, 4 and 5, discussed above. The CAISO has indicated that it will not adopt a 5-minute scan rate for Non-Spin, since Non-Spin is considered an Ancillary Services product and subject to more stringent telemetry requirements.

The working group believes that further work should be done to explore cost-effective options to meet telemetry requirements. This would include statistical sampling along with alternative technology options.

Summary of Baseline Issues and Proposed Solutions

Baselines are used to calculate the performance of DR resources in the CAISO's markets and provide input to the settlements process. The North American Energy Standards Board (NAESB) has adopted Model Business Practice Manuals for Metering and Telemetry that provide guidance on DR performance reporting. The CAISO has provisions for some but not all of the NAESB baselines in its BPMs and tariffs. The subgroup has proposed to add additional baselines consistent with the NAESB standards and to develop requirements for the use of statistical sampling. In addition, the CPUC and CAISO baselines do not fully match and some effort should be made to determine if it is desirable and possible to conform them.

Subgroup Proposals

1. Enhancements to the CAISO tariff and BPMs to allow for custom baselines for energy and operating reserves where they can be demonstrated to be more accurate than standard baselines.

2. To add the Meter Generator Output baseline for energy and operating reserves, which will help with calculating the performance of DR with behind-the-meter storage.[6]

3. To add the Maximum Base Load Performance Evaluation for PDR Capacity No Pay Dispatch Performance to the current provision for Meter before/Meter after. This would allow performance to be evaluated based on the ability of a DR resource to maintain usage at or below a set capacity level. The subgroup later withdrew this proposal.

The working group notes that under CAISO processes, a combination of a 10-in-10 baseline is used combined with Meter Before/Meter After to assess capacity for Pay No Pay Dispatch Performance for ancillary services.

4. After the subgroup report to the CAISO in February, the subgroup considered adding another means of assessing performance besides the use of baselines, which is the use of a comparison group of non-participants. This approach is used in the load impact evaluation of mass market retail DR programs like the PG&E Smart AC program.[7] The working group will provide recommendations to the CAISO for how to incorporate this type of evaluation in its new DR systems.

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[6] The working group understands that compliance with the utilities' submetering rules is required, e.g. PG&E Electric Rule 18.

[7] See 3a. PG&E 2014 Smart AC Load Impact Evaluation.pdf.

CAISO Response

CAISO has indicated to the working group that it will adopt its recommendations above, on the condition that any alternative or custom baseline proposal adheres to the NAESB parameters. The working group is currently engaged in considering how to implement additional baselines. To evaluate and qualify new baselines, there should be a forum, which could be the working group, for addressing these issues that includes the CAISO, CPUC, LSEs, DRPs, consumer representatives and any other interested parties. The working group is recommending that a motion be filed at the Commission requesting continuation of its activities to at least address baseline and statistical sampling issues.

Once the details of the baseline and statistical sampling proposals have been vetted, they will have to go to the CAISO for implementation. To date, FERC has indicated to the CAISO that the details of the baselines will have to be incorporated into the CAISO tariff. If this FERC position does not change, any baseline changes will require a stakeholder initiative at the CAISO. The current expectation is that the baseline issues will be addressed in the CAISO stakeholder initiative on Energy Storage and Distributed Energy Resources. The working group recognizes that the process for modifying the CAISO systems to accommodate a new baseline methodology will take at least a year and a half.

Differences Between CPUC and CAISO

The subgroup discussed two specific differences in the approved baseline calculations by the CPUC and CAISO that may warrant further discussion. One difference is that the CAISO baseline software requires a day-of adjustment of 20% to the 10-in-10 non-event day load calculation, whereas the Commission has authorized the use of a 40% day-of adjustment for some programs.[8] The impact of this lack of consistency is not clear in terms of the consequences for Commission-authorized retail utility DR programs compared to other resources in the CAISO markets. The CAISO does not believe that the difference is significant, citing a study performed for the DR Measurement and Evaluation Committee by Christensen Associates entitled "2013 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs, Volume 2: Baseline Analysis."[9] However,

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[8] D. 12-04-045, Ordering Paragraph 10, allowing a 40% day-of adjustment for the Capacity Bidding Program.

[9] Christensen Associates summarizes in its May 7, 2014 study presentation that "day-of adjustment often improves accuracy and reduces bias, but level of cap is less important." (Slide 15). In the Baseline Analysis study itself, Christensen Associates concludes, "... there are few clear patterns of the degree of improvement in performance under different adjustment cap restrictions. For many of the programs, caps above 20 or 30 percent were not binding." (at p. 26)
See May 7, 2014: Demand Response Load Impacts Evaluation Workshop materials on the CPUC website at:
http://www.cpuc.ca.gov/PUC/energy/Demand+Response/DemandResponseWorkshops.htm

some DRPs do not agree, claiming that the consequence for settlement purposes is different from that for calculating load impacts under the load impact protocols. In addition, some parties have articulated that some current retail programs provide incentives to customers that are unrelated to performance measurement (e.g., Smart AC customer incentives versus Smart AC load impact studies) and, as such, it is not clear that a requirement of matching retail and wholesale measurements would be meaningful. A further assessment of the consequences should provide an indication of whether this is an issue requiring any policy action.

Another difference between the CPUC- and CAISO-allowed baselines is that the Commission requires baseline calculations on a per-customer basis whereas the CAISO performs these calculations on a resource-wide basis. This difference results in unequal determination of performance between wholesale and retail DR settlements. Whether this difference is a problem is a policy issue to be resolved between the CPUC and the CAISO. We note that computing per-customer baselines would require a major increase in the amount of meter data to be uploaded and stored by the CAISO; it is the working group's opinion that the CAISO will find such a direction undesirable. Thus, if it is determined to be preferable to eliminate the difference, one solution would be for the CPUC to reconsider its per-customer baseline calculation requirement.

Finally, at the May 28 working group meeting, there was a discussion of a difference in how the utilities and the CAISO would calculate the performance of customers doing net energy metering with onsite solar distributed generation and participating in wholesale DR. It was stated that the utilities set grid exports to zero since they are not DR, whereas the CAISO, in establishing its resource baseline, includes exported energy. This results in different CAISO and CPUC baseline calculations. The working group has not had time to consider this issue in any detail but suggests that there be a forum for discussing how to determine the performance of customers with onsite generation engaged in net energy metering and DR. The working group also notes that the Joint Utilities Tier 3 advice letter to implement the demand response auction mechanism raised a concern about this issue under "Customer Participation Limitations".[10] Some members of the working group suggest that a solution needs to be identified that would treat the solar portion of a NEM export correctly for retail consideration while allowing any demand curtailment to be treated as load only for the purposes of wholesale demand response.

[10] Advice Letter 4618-E for PG&E, 3208-E for SCE, and 2729-E for SDG&E, filed April 20, 2015.

Summary of Resource Requirement Issues and Proposed Solutions

The Resource Requirements subgroup was also called the LSE subgroup. It focused its attention on the challenges to integration created by the CAISO's requirement that any DR resource be a minimum of 100 kW in size and that it represent only one LSE, DRP, and sub-Load Aggregation Point (subLAP). There are numerous LSEs, including electric service providers (ESPs) and community choice aggregators (CCAs), as well as the utilities. In addition, except for SDG&E, each utility's service area has more than one subLAP. In early efforts to integrate DR into the CAISO markets, these requirements resulted in resources that could not reach the level of 100 kW.[11]

A major reason for the one-LSE requirement is the implementation of the default load adjustment (DLA) requirement of FERC Order 745 (currently on appeal to the U.S. Supreme Court) and incorporated into the CAISO's tariff. To ensure the LSE is neither harmed by, nor benefits from the load modifying actions of the demand response provider, the DLA adjusts the LSE's load schedule for the actual amount of demand response delivered when a DR resource delivers energy below the calculated Net Benefits Test (NBT). Under the current FERC-approved CAISO market design, since the DLA applies to the aggregate resource and not to the underlying LSE service accounts, the CAISO states that the DLA settlement is only possible if each PDR or RDRR resource is associated with one LSE, since the quantity of demand response delivered by the aggregation could not be decomposed by LSE unless the baseline calculation was also performed at the LSE level.

Another consequence of implementing this requirement at the CAISO was a further requirement that an LSE authorize the participation of each of its customers in a resource of a DRP that is not that same LSE. This provision in the CAISO's Metering BPM unintentionally provides the possibility for an LSE to delay or prevent all of its customers from participating in wholesale DR by not enrolling in the CAISO DRS, because without this enrollment a DRP could not begin the customer registration process. However, if the LSE was enrolled in the DRS, the BPM provides up to 10 business days for the LSE to validate (or take exception to) its customers as being registered in a PDR. If the LSE takes no action, the customers are automatically approved for the PDR by the CAISO.

Subgroup Proposal 1: Multiple LSEs in One Resource

1. That the CAISO support the ability to combine more than one LSE in a resource by creating the ability to perform LSE-specific DLA calculations within the resource-level settlement calculation.

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[11] Appendix B to PG&E Testimony in R. 13-09-011, May 6, 2015, p. B-11.

CAISO Response to Proposal 1

The CAISO has responded, indicating that it cannot eliminate the requirement for each PDR or RDRR resource to be associated with a single load-serving entity (LSE), i.e. one PDR/RDRR to one LSE, with the DLA settlement mechanism in place. The CAISO stated that it cannot decompose the uninstructed imbalance energy (UIE) quantities to assign the DLA settlement quantity to each underlying LSE since a PDR and a RDRR resource's performance is based on the aggregate baseline performance of the resource, not on the baseline performance of the individual LSE service accounts and then summed together under the aggregate PDR or RDRR, under the current CAISO settlement system. In other words, the CAISO states that it cannot determine the uninstructed imbalance energy for each LSE's service accounts and, therefore, cannot properly settle the DLA with each LSE. Thus, the CAISO says it must maintain the one PDR/RDRR to one LSE construct while the DLA is in place. [12]

SCE comments that the Uninstructed Imbalance Energy (UIE) of each LSE's service account (SA) is not required; only the aggregated amounts by LSE are required. In order to perform settlements, the required information is: 1) the award by PDR/RDRR (where the PDR/RDRR consists of multiple sub-resources by LSE) and 2) the performance by sub-resource (i.e. the LSE). SCE comments that 1) is the market award by PDR/RDRR similar to today (except that the new resource would be larger due to aggregation) and that 2) can be provided through the DRP's meter data submission based on the sub-resources registered in the DRS. SCE says that these are the same two pieces of information used currently to calculate the settlement of PDRs/RDRRs for a DRP and the DLA for an LSE.

The CAISO responds that it performs the baseline calculation on the sum of all the meters that make up a PDR/RDRR, not on groups of meters. If multiple LSEs make up a single PDR/RDRR, the ISO cannot decompose the DLA calculation for each LSE. To make a PDR/RDRR work with multiple LSEs, the baseline would have to be computed for each LSE and then summed together to create the response of the aggregate PDR. For instance, if a resource had four distinct LSEs, four individual baseline calculations would have to be performed and then summed together. This is the equivalent of simply having four distinct PDRs/RDRRs combined into one. This is a different PDR/RDRR construct than contemplated by the CAISO and its stakeholders when designing PDR/RDRR. Section 4.13.4.1 of the CAISO Tariff states, "The CAISO will calculate the simple hourly average of the collected Meter Data to

[12] The CAISO states that the Default Load Adjustment (DLA) quantity is the actual baseline computed performance of the entire PDR or RDRR, in aggregate. It is not a summation of the baseline performance of each sub-resource by LSE. Thus, how one sub-resource actually performs relative to another is indeterminable under this settlement construct. It is the performance of the entire resource, in aggregate, that matters. Given this fact, the CAISO cannot parse the performance of one LSE's sub-resources with another LSE's to assess the DLA quantity that would then be assigned to each underlying LSE.

determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource."

Subgroup Proposal 2: Eliminate DRP/LSE Agreement Requirement

2. That the agreement between a DRP and an LSE currently required in the CAISO's BPM before a customer can participate in a wholesale resource either be eliminated or changed so that an LSE cannot inhibit participation by retail customers in wholesale markets by not approving its customer's participation with the DRP. Section 12.3 in the CAISO Metering BPM states:

> "The Demand Response Provider Agreement requires that the DRP have sufficient contractual relationships with the end use customers, LSE, and UDC and meet any Local Regulatory Authorities' requirements prior to participating in the CAISO Markets."

By contrast, Section 4.3 of the CAISO's standard DRP agreement specifies that the DRP must "certify" that any DRP-LSE agreement "required" by the Local Regulatory Authority (LRA) be "fully executed."

The subgroup recommended that no agreement be required between a DRP and a non-utility[13] LSE regarding a customer's participation or that it be changed so that a non-utility LSE cannot prevent participation by the load in the wholesale market. The CAISO has indicated that it does not require such an agreement if the LRA does not require one, and the working group is not aware of any party supporting that such an agreement should be a requirement. The working group is also not aware of any current requirement by the CPUC, as an LRA, for such a DRP-LSE agreement. Thus, if the CPUC, as an LRA, does not have such a requirement, it should formally convey that information to the CAISO so that the CAISO can eliminate any requirement for such an agreement. Additionally, the working group recommends that the CAISO modify its BPM language to eliminate need for such an agreement. The CAISO has indicated that it is willing to modify the BPM language to clarify this issue and align the BPM language with what is in the demand response provider agreement if it is so informed by the Commission.

Subgroup Proposal 3: List All LSEs in DRS/DRRS

3. That all LSEs be listed in the CAISO's DRS or subsequent DRRS so that there are no delays to customer participation from an LSE's failure to register. The CAISO could add all LSEs or the DRPs should be able to initiate such addition before or at the time of new DR resource creation. There could be jurisdictional issues here. However, FERC ruled in Order 719 that LSEs cannot withhold permission for their customers to participate with third party DRPs. The intention of this and the previous proposal is to facilitate customer participation in wholesale DR. The working group notes that at the beginning of its process, the utilities and two other

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[13] An agreement is required by the Commission for a DRP and a utility.

LSEs were included in the DRS. As a result of this issue being raised by the working group, most ESPs are currently enrolled in the CAISO's DRS. In total, 12 ESPs, large and small, are now enrolled. However, at this time there are no CCAs enrolled.

We recommend that the Commission send a letter to all of its jurisdictional LSEs that are not currently enrolled in the CAISO's DRS, *i.e.*, any unenrolled ESPs and CCAs, advising them to enroll in the CAISO's DRS and subsequent DRRS. The working group also recommends that all new CPUC-jurisdictional LSEs be automatically enrolled in the CAISO's DRS and subsequent DRRS per Commission formal written guidance to the CAISO to do so. Given that the Commission only has limited jurisdiction over CCAs, the working group recommends that the CPUC provide written advisement to all new CCAs that they should enroll with the CAISO's DRS and subsequent DRRS as part the CPUC's response to the new CCA when the CPUC reviews the CCAs implementation plan. The working group believes this heightened awareness for new LSEs will help to mitigate the present issue of not all LSEs registering within the CAISO's DRS. The Commission should also provide guidance to new ESPs to enroll with the CAISO DRS and subsequent DRRS as well.

Subgroup Proposal 4: Correct DLA Calculation

4. That a correction be made to the calculation of the DLA so that if a resource receives an award in the day-ahead market at or above the NBT and then delivers excess energy in real-time, the DLA only applies to the portion of the energy delivery that is paid below the NBT in the real-time market. Several participants in the working group believe that the current settlement process should be changed to make this correction in order to be consistent with the tariff.

The tariff states:

> ***11.5.2.4***
>
> ***Adjustment to Metered Load to Settle UIE***
> *For the purpose of settling Uninstructed Imbalance Energy of a Scheduling Coordinator representing a Load Serving Entity, the amount of Demand Response Energy Measurement delivered by a Proxy Demand Resource or Reliability Demand Response Resource that is also served by that Load Serving Entity and that is paid a Market Clearing Price below the threshold Market Clearing Price set forth in Section 30.6.3.1 will be added to the metered load quantity of the Load Serving Entity's Scheduling Coordinator's Load Resource ID with which the Proxy Demand Resource or Reliability Demand Response Resource is associated.*

The CAISO asserts that its calculation is correct; however, even with the following explanation from the CAISO, some working group participants are unclear if the implementation is either consistent with the CAISO tariff language or with the expectation of the commission and stakeholders involved in the proceeding on cost allocation. The working group is unlikely to come to a consensus with the CAISO on this matter.

Because there can be a significant settlement difference between these two methods of calculation, the working group suggests that utilities, ESPs and CCAs individually or collectively determine whether this is an issue they want to pursue, and then pursue it directly with the CAISO.

In addition, it should be understood that the DRPs do not see the DLA as a settlement risk, but in a construct where LSE's can withhold approval for their customers, it can be seen as a blocker to reach agreements with LSEs or to get registrations approved in the market.

CAISO Response to Subgroup Proposal 4

The CAISO states that it believes that the Default Load Adjustment (DLA) settlement mechanism is calculated correctly and in accordance with its tariff filing in compliance with FERC Order 745.

The CAISO further explains: Originally, the CAISO and stakeholders who helped design PDR found it prudent to apply the DLA to all PDR transactions. The DLA resolved difficult cost allocation concerns in the CAISO market, and intentionally deferred these issues to be resolved by the local regulatory authority. The CAISO's original tariff approved by FERC applied the DLA to all PDR transactions, eliminating wholesale market settlement impacts when a one entity schedules the load that another entity curtails.

FERC later issued Order 745. This order implicated wholesale demand response compensation rules and introduced the Net Benefits Test (NBT). The CAISO and other ISOs and RTOs interpreted Order 745 as requiring the NBT be a bid threshold. If a demand response provider's bids met the NBT threshold, then those bids would be considered in the CAISO optimization. If those bids did not meet the NBT threshold, then those bids would be thrown out. The CAISO also argued in its Order 745 compliance filing the DLA should still apply to all PDR transactions since the CAISO pays PDR resources the full locational marginal price (LMP). FERC rejected the CAISO's compliance filing and clarified that (1) the NBT is not a bid threshold—the CAISO still has to consider bids that don't meet the NBT, and (2) that the CAISO must apply the DLA to PDR transactions when the NBT threshold is not met.

In further compliance with FERC Order 745, the CAISO submitted Tarff Section 11.5.2.4, which is the controlling language. This section plainly states that if the market-clearing price (not bid) is less than the clearing price determined by the NBT, then the DLA applies. Additionally, the CAISO tariff clarified that the DLA applies to the LSE's uninstructed imbalance energy settlement, not to the demand response provider's bids. FERC accepted this language on compliance, which guided the CAISO's current DLA settlement methodology. The ISO Tariff states:

11.5.2.4 Adjustment to Metered Load to Settle UIE

For the purpose of settling Uninstructed Imbalance Energy of a Scheduling Coordinator representing a Load Serving Entity, the amount of Demand Response Energy Measurement delivered by a Proxy Demand Resource or Reliability Demand Response Resource that is also served by that Load Serving Entity and that is paid a Market Clearing Price below the threshold Market Clearing Price set forth in Section 30.6.3.1 will be added to the metered load quantity of the Load Serving Entity's Scheduling Coordinator's Load Resource ID with which the Proxy Demand Resource or Reliability Demand Response Resource is associated.

Per the CAISO's FERC approved tariff, the CAISO does not evaluate the NBT based on the bidding behavior of the demand response provider. Rather, the CAISO simply evaluates the market-clearing price used to settle the LSE's uninstructed imbalance energy in real time against the NBT price threshold. If the imbalance energy at the market-clearing price is above the NBT threshold, then that LSE's uninstructed imbalance energy is beneficial and the DLA does not apply; otherwise that energy was not beneficial and the DLA applies.

Finally, the DLA is often construed as imposing wholesale market risk on the demand response provider; however, the CAISO states that is an incorrect understanding of the DLA. The demand response provider's wholesale market settlement is unaffected by the DLA. The DLA is a settlement mechanism that simply adjusts the LSE's uninstructed imbalance energy settlement quantity to eliminate the double payment in the CAISO market whenever that uninstructed imbalance energy quantity is deemed not beneficial per the NBT threshold test. The DLA imposes no wholesale market costs on the demand response provider.

Subgroup Proposal 5: DLA Elimination

5. That the DLA be eliminated. This would only be possible if FERC revises Order 745 to eliminate the DLA after U.S. Supreme Court review and possible remand and if such elimination were upheld, if challenged. The CAISO tariff must be approved by FERC and consistent with its orders. The elimination of the DLA would greatly simplify settlements for DR resources in wholesale markets. However, elimination of the DLA would raise the once-contentious "double payment" issue that existed prior to the adoption of the DLA and the NBT, and some resolution of that issue would be required.

The Commission may wish to convene the parties interested in the DLA issue to discuss the pros and cons of eliminating the DLA even before the Supreme Court acts.

CAISO Response to Subgroup Proposal 5

The CAISO says that it plans to maintain the DLA at least until the Supreme Court issues its decision on Order 745. In the interim, the CAISO wants to solicit stakeholder feedback on whether the DLA settlement construct should be eliminated altogether. The CAISO desires further stakeholder input, both from SIWG participants and other market participants, to assess the level of effort and stakeholder vetting that would be required should a stakeholder initiative be launched to consider eliminating the DLA. However, the concerns and issues that resulted in the DLA, i.e. the double payment issue, would have to be addressed. For instance, the CAISO wonders if the LSEs in the CAISO balancing area are comfortable covering the double payment that the DLA sought to remove. It also wonders if market participants are going to raise the LMP-G issue again and seek to redress cost allocation issues through the CAISO market (which the DLA effectively shifted to the local regulatory authorities to decide and resolve). Depending on the outcome of the Supreme Court decision, just and reasonable wholesale demand response compensation may be up for discussion and a decision by FERC; thus the CAISO believes waiting a little longer is prudent.

Open Issues Identified by the Working Group

The working group identified other issues that make the integration of DR into the CAISO's markets more difficult. The working group believes that these issues should be addressed as soon as possible to eliminate potential barriers they create. Where these issues are matters for the Commission to decide, the Commission must decide on the appropriate vehicle(s) for addressing these issues. Their resolution will require participation by the CAISO. The working group recommends that each be addressed in a transparent process that allows interested parties to participate, achieving as expeditious resolution as possible, in order to meet the Commission's bifurcation goals.

1. Issues with Changes to CAISO DRS and Creation of DRRS

The CAISO is in the process of making changes to its Demand Response System (DRS) to accommodate more bidding of DR resources into the CAISO's wholesale markets starting in the summer of 2015. Participants such as Pacific Gas and Electric (PG&E) and Olivine have been bidding despite these existing limitations. However, Southern California Edison Company (SCE) is expected to integrate its Summer Discount Program (SDP) and its Base Interruptible Program (BIP) into the CAISO markets as Reliability Demand Response Resources (RDRR) this summer. SDP in particular involves hundreds of thousands of customers, which necessitated the development of a new Location Application Programming Interface (API). The Location API "went live" in March 2015, but it has not been without difficulties.

The biggest present concern is that, under the new CAISO design with the Location API, an Aggregated Location (ALOC) can no longer be edited if it is in an active registration; instead, a registration must expire or be terminated to allow individual locations to be removed or added to an ALOC. The prior system design provided DRPs the ability to submit a registration for review with locations in an active registration if the effective dates were not overlapping. With foresight, this allowed DRPs the ability to pre-register a new set of locations and enter into the review process for a modified registration prior to the termination or end dating of the registration being replaced. The new system design removing the ability to set a future termination date imposes a gap when there is a desire to modify a confirmed PDR or RDRR registration ahead of time, since the new registration cannot be created and enter into the review process until after the current registration termination date passes. Due to the requirement for the new registration to be reviewed and confirmed, a gap would occur between the termination of the prior registration and confirmation of the new registration. This gap could last from 2 or 3 days to a maximum of 10 business days (maximum of 10 business day for LSE/UDC review in addition to a maximum of 10 business days for CAISO to confirm the reviewed registration). While the registration is not in a confirmed state, the PDR or RDRR resource cannot participate in the market. The process would be required for the addition or removal of one or many locations. This significantly de-values the DRP's underlying portfolio by keeping it out of the market. It may also interfere with the resource's ability to meet resource adequacy requirements, although the CAISO has indicated that if a resource cannot meet must-offer obligations because of CAISO systems issues, it would be deemed "not able" to comply and would not be penalized.

CAISO Response:

The CAISO says that this item will be resolved and is currently in scope for the enabling demand response phase 2 business requirement specification developments being shared and discussed as part of the CAISO Customer Partnership Group.[14] Requirements will continue to be developed with a goal for implementing phase 2 in the first half of 2016.

2. Discrete Dispatch

Discrete dispatch is not available in the day-ahead market for Reliability DR Resources (RDRR) to accommodate customers with stair-step-like loads that can only be shed in discrete increments. The CAISO allows for discrete dispatch for RDRR in the real-time market but not if those resources dually participate, under Commission-approved orders, in the day-ahead market. Many of the existing DR programs have limitations on the degree to which they can accept partial dispatch in the day-ahead market due to the nature of the underlying loads. Participation in the day-ahead markets by these resources could be lost if there is no means of accommodating the "lumpy" nature of the loads, or program changes and technology may need to be employed to accommodate partial dispatches when a demand resource clears at the marginal resource.

SCE comments that gas-fired generators can have a minimum generation level and forbidden operating zones which cause the same inefficiencies in running the market as those the CAISO argues require partial dispatch for DR. (See CAISO Response below.) SCE also comments that gas-fired generators can set $P_{min} = P_{max}$[15] which is another mechanism for implementing a discrete dispatch. SCE says that the forbidden operating zones issue is an economic issue for these generators. It also points out that resources with discrete dispatch receive lower market revenues without these limitations and suggests that if the additional revenues gained from removing these limitations are less than the cost of removing the limitations, the resource owner should not be forced to incur those expenses or be kept out of the market. SCE also points out that some legacy utility DR programs are typically not capable of providing partial dispatch and could incur significant costs (especially for

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14 http://www.caiso.com/informed/Pages/MeetingsEvents/UserGroupsRecurringMeetings/Default.aspx

15 minimum and maximum operating points

mass market programs) if required to implement telemetry to participate as PDR in the CAISO markets.

CAISO Response:

The CAISO states that it will not be modifying its discrete dispatch policy.

The CAISO states that discrete dispatch is a special circumstance. A partial dispatch can occur when a resource happens to be the marginal resource cleared in that hour (day-ahead) or interval (real-time). If the system only needs a share of a resource to balance the grid, it will clear or dispatch only that portion needed as any excess energy would create an imbalance and force the re-dispatch of other economic resources.

The CAISO says that during the RDRR policy development process with stakeholders, this specific policy was vetted and the decision was made to not provide discrete dispatch for economic (non-emergency) demand response resources as it creates market inefficiency and can necessitate re-dispatch of other economic units.[16]

RDRR was afforded a discrete dispatch option since RDRR resources are infrequently dispatched, i.e. only in an emergency. In an emergency, the CAISO is more comfortable with a discrete response because it is trying to rapidly deploy as much energy as possible to ensure reliable operation. In these emergency situations it is unlikely the CAISO will have a marginal resource dispatch concern. That is, the CAISO would likely not have to re-dispatch resources down to re-balance for the over-delivery of energy from discretely dispatched resources in an emergency. For example, if there is a large discrete dispatch resource, say 100 MW, and the system is only calling for 10 MW of marginal capacity, discrete dispatch requires the CAISO dispatch all 100 MW, which means the CAISO must back down cheaper "economic" resources to accommodate the energy from this more expensive discrete resource. This creates inefficiency and a sub-optimal market solution, which has a cost.

Regarding SCE's comment, the CAISO responds:

A PDR can effectively achieve a discrete dispatch like a generator by setting its P_{Min} at .01 less than the P_{Max} of the resource, and registering a P_{Min} and start-up (i.e., shut-down) cost. This could work for a PDR that has a fixed load at all times (which is

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[16] Section 3.4.1.1.1- RDRP resources that elect the constrained output generator (COG) option will be treated as marginal resources in the day-ahead. Thus, a RDRP COG resource that is the marginal resource in the day-ahead energy market could clear a marginal megawatt quantity of energy. In other words, the CAISO will not enforce a discrete or block megawatt clearing of energy in the day-ahead market for RDRP COG resources.

unusual). This is the same requirement for Constrained Output Generator (COG) resources. The CAISO tariff states:

> A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status must make an election to have the resource treated as a COG before each calendar year by registering the resource's P_{Min} in the Master File as equal to its P_{Max} less 0.01 MW ($P_{Min} = P_{Max} – 0.01$ MW) within the timing requirements specified for Master File changes described in the applicable Business Practice Manual.

There were two issues market participants discussed in formulating RDRR. The discrete dispatch option for RDRR was compared to a COG, but not particularly analogous to a COG because the P_{Max} of an RDRR is assumed not constant. So unlike a COG, it was not possible to place the P_{Min} and P_{Max} .01 MW apart given loads typically change by hour. In the RDRR development process, market participants discussed the concept of a variable maximum and variable minimum (V_{Max} and V_{Min}) specifically to address this "P_{Min}" issue, but this concept was not feasible to implement or to optimize in reality.

Why is this "P_{Min}" distinction important to PDR and RDRR versus COG and other modeled resource constraints, such as forbidden zones? The answer is that resource constraints, such as P_{Min} and forbidden zones, are priced/valued in the optimization. The CAISO market optimizes resources on three-part bids-representing start-up cost, minimum load cost, and energy cost. The discrete dispatch of a RDRR is only based on energy since there is no P_{Min} value, so start-up and minimum load costs are not factored into the optimization (and, in fact, are prohibited for RDRR by design). If these costs were included, DR would look less optimal (SCE makes this same point for generators with constraints). There are other unique restrictions on COGs. For example, COGs are treated as flexible (not discrete) resources in the day-ahead market, and are committed to their discrete amount in the residual unit commitment process. Additionally, COGs are paid a calculated cost, not their bid cost (if the two differ). Many restrictions exist for COGs because of the market inefficiencies they create, and, as a result, there are extremely few MWs registered as COGs in the CAISO market.

Unlike COGs, the CAISO opted to allow a discrete dispatch on RDRR, with no restrictions, understanding that the energy from these resources would be needed in emergency conditions, which shouldn't trigger the same market inefficiency concerns. To petition for a discrete dispatch option for PDR (i.e., economic, non-emergency resources) without restrictions would not be acceptable. Unlike PDR, or even RDRR participating in the day-ahead markets, the CAISO has not supported a discrete dispatch option for these resources that participate economically, day-to-day because of the complexity of rules/restrictions that would have to be developed, the time and effort to put these issues through a stakeholder initiative, and the fact that discrete dispatch is not considered to be viable in the future. The market does not benefit from a growing fleet of discrete dispatch resources. DR operators and technology need to solve the marginal dispatch challenge and not defer its resolution further into the future.

3. Implementation of Minimum Run Time for DR

DR has zero $P_{min,}$. The Integrated Forward Market (IFM) does not accommodate a minimum run time for DR (i.e., to specify minimum time periods in excess of 1 hour). This is an important issue in cases where a resource may have operational constraints that require a reduction to continue for multiple hours, and is a feature supported for other resource types, increasing the operational challenges for DRPs.

CAISO Response:

For bids cleared in the CAISO day-ahead market, a one-hour minimum run time is respected. The cleared day-ahead bid is the resource's hourly schedule. The one-hour run time becomes a factor for cleared real-time bids. However, the CAISO says that a minimum run-time can be accommodated for real-time bids through resource attributes registered in the CAISO Masterfile. In order for the minimum run-time to be recognized, the demand response resource needs to register a P_{min} slightly greater than zero and include a shut-down (like a start-up) cost.

4. Day-ahead NBT Calculation

The Net Benefits Test is calculated based on real-time market prices even when resources receive a binding commitment in the day-ahead market. This can lead to unanticipated Default Load Adjustments. Can the Net Benefits Test be changed to use day-ahead market prices for resource that are committed in the Day-Ahead market (DAM)?

CAISO Response:

The CAISO says it must maintain the current implementation of the Net Benefits Test as specified in the CAISO Tariff and as approved by FERC and that the Net Benefits Test is based on real-time bids, not on day-ahead bids. Section 30.6.3.1 of the ISO Tariff states that the ISO builds its NBT supply curves using "...all Bids into the Real-Time Market from any Generating Unit." Thus, a PDR or RDRR resource is net beneficial when tested and clears against the CAISO's monthly real-time on-peak and off-peak NBT price, not on a Day-ahead NBT price. For this reason, the CAISO does not use a day-ahead NBT.

The working group notes that there is a difference of interpretation of this section of the tariff between the CAISO and some other participants in its markets.

5. Data Accuracy and Scheduling Coordinator Liability

The scheduling coordinator (SC) is responsible under the CAISO tariff for the accuracy of Settlement Quality Meter Data (SQMD). Concerns have been raised that the current accuracy requirements as stated may create a workload burden and potential risk for the SC submitting the data.

Commission accuracy standards require that utility meters be within "+or -2%" accuracy. The CAISO requires 100% accuracy for meter data, despite the fact that the individual meter readings provided by the utilities themselves have accepted accuracy tolerances. The working group recommends that the CAISO clarify its requirements to refer to the accuracy based on the source data provided to the SC. Since the CAISO defers to the Local Regulatory Authority on the use of RQMD for SQMD, its requirements should reflect the Commission's standards at +/- 2%.

The 100% accuracy requirement for an aggregation of locations such as PDR or RDRR would also require the SC to have meter data for all service accounts within the aggregation, aggregating into a single value for submittal to the CAISO. Any changes in underlying meter data would impact the aggregated resource value.

Underlying meter data can change for a variety of reasons. The RQMD meter data provided by the utility includes estimates as part of approved VEE processes. Although the changes may be minimal, the 100% accuracy level would require the SC to reprocess and resubmit meter data whenever there is any change to any underlying meter data. These changes could be quite often for some types of customers, creating a significant processing burden. Additionally, if underlying meter data changes after the T+48 submittal cut off, the SC is required to resubmit the updated data and pay a "fine" of $1000 per day.[17] The SC is also subject to an annual meter data audit to ensure accuracy and could be subject to sanctions for issues identified.

These underlying meter data changes would likely not impact the market and create any market resettlement issues but could require a significant amount of effort by an SC to manage and ensure 100% accuracy. A range such as the band of + or -2% for an aggregated resource would provide some 'bandwidth' for minor changes to the underlying meter data without creating market impacts.

The working group recommends that there be an effort to review and codify acceptable data accuracy limits for SQMD as they relate both to the source data and to an aggregation. These efforts should be compatible with the efforts for statistical sampling and alternative baseline issues.

CAISO Response:

The CAISO metering requirements conform to NAESB standards. The NAESB standards point to CAISO governing documents. In the case of SC-metered entities, such as PDR and RDRR resources, the CAISO defers to the Local Regulatory

[17] The utilities respond that under Rule 24, they would be responsible for the fines as they provided the meter data if there were corrections after T+48. However, the timing and process for reimbursing the SC are not clear.

Authority to authorize meter data as settlement quality (SQMD).

6. Statistical Sampling

A process must be created to analyze various statistical sampling techniques and agree on ones that will be acceptable for use by DRPs that bid into the CAISO's markets. Currently, there is no agreed-upon sampling methodology or technique. This will be particularly important for mass market DR, a subject for the next phase of the CPUC's Rule 24 proceeding. The CAISO tariff permits the use of statistical sampling for baselines (Type II). Statistical sampling has also been discussed in the CPUC Rule 24 proceeding to provide revenue quality meter data (RQMD), which would become the basis of SQMD. DRPs in that proceeding were very interested in sampling.

CAISO Response:

Given the development of the new DRRS system and the need to specify requirements for that system, including handling different baseline types, The CAISO prefers that the baseline subgroup of the SIWG continue its work and finish its recommendations to inform the DRRS development effort after filing the SIWG report.

7. Requirements for DR to Qualify for Local Resource Adequacy (RA)

There is a need for specific requirements for PDR and RDRR to qualify for local RA. This should be explicitly addressed in the Commission's resource adequacy proceedings.

8. Other Issues:

a. Could a PDR resource be derated (i.e. its size in kW reduced) if part of it is available for more dispatch than the 24 hours per month required under the must-offer obligation? This is a matter for the CAISO.

b. Are the CPUC and CAISO willing to reconsider allowing some dispatch of DR by default load aggregation point (DLAP), rather than subLAP? If yes, some existing utility DR programs could be integrated more quickly.

SCE comments that allowing DLAP Dispatch under some threshold of MW could be used to relieve congestion across boundaries such as Path 15/26 or between SCE and SDG&E. It also comments that if a resource at the DLAP level could cause congestion, it would be better for the CAISO to learn this when it runs the day-ahead market so it can optimally solve the problem.

<u>CAISO Response</u>**:** The CAISO operates a nodal market and optimizes the system around the Pricing Nodes (PNode) not by load aggregation points, be they default load aggregation points or sub-load aggregation points. Optimizing the system by load aggregation points is analogous to how the CAISO used to optimize the system

by congestion zones, which, among other reasons, was discarded since it did not capture the intra-zonal congestion that occurred within the congestion zones. The nodal market resolves all constraints, both intra- and inter-zonal constraints, like Path 15/26. Thus, the power flow model and system optimization must be done at the nodal level, not at a zonal level.

c. How can DR be incorporated into load bids? This is a potential way to integrate load-modifying DR into the market that is currently not available.

<u>CAISO Response</u>**:** This option is available today as load-serving entities have the ability to place a price curve on their load bids. LSEs may already be factoring demand response load impacts into their day-ahead forecasts and load bidding strategies. Additionally, LSEs could submit separate load bids with price curves that are tied directly to their load modifying demand response capability, if so desired.

d. Is it possible to use hourly SQMD data to obtain 5-minute metering for RDRR settlement? Currently, CAISO's Metering BPM only mentions use of 15-minute SQMD data. If hourly SQMD data could be used, DR programs with residential load whose meters currently only collect meter data on an hourly basis could be bid into the CAISO's markets without the cost of changing meter reads to a 15-minute basis. However, using 60-minute data would increase the concern noted above about data accuracy. Thus, these two issues are connected and must be addressed together.

Attachment 1: Joint Proposal for SIWG Charter

Charter for
Supply Resource Demand Response Integration Working Group
July 25, 2014

1. **Purpose of Working Group:**
The purpose of the Working Group is twofold: 1) to identify areas where requirements for integration of supply resources demand response into CAISO markets are adding significant cost and complexity, to determine whether these requirements can be simplified or changed without creating operational problems, to prioritize these possible changes, and to resolve them; and 2) to identify program modifications and operational techniques to make demand response programs more suitable and successful as supply resources. This is not a policy group but a technical group to discuss IT, systems, and operational matters.

2. **Products:**
a. The first Working Group product should be a list of areas for change, priorities, proposed solutions (both from a CAISO perspective and from an IOU program redesign perspective) and a time-line for resolution.
b. The output of the Working Group will be input into IOU demand response applications, CAISO stakeholder processes, resource adequacy proceedings, long term procurement proceedings, possible review of Rule 24/32 requirements adopted by the CPUC and other possible proceedings as appropriate.

3. **Structure:**
The Working Group will consist of members of the staffs of the investor-owned utilities (IOUs), demand response providers (DRPs), CAISO, and CPUC, as well as other load-serving entities (LSEs), customer representatives, and public interest groups, if interested. All members should be conversant in the technical aspects of integration of demand response into CAISO markets, Rules 24/32, and resource adequacy requirements.

4. **Governance (process and principles):**
Process: The group should focus on: 1) technical solutions and processes that may decrease the cost and complexity of integration of DR into the CAISO markets, and 2) program design changes or technology solutions that reduce the complexity and cost of integration. While the CAISO is the ultimate entity to approve changes to its requirements, the group should collaborate to find mutually-acceptable solutions.

5. **Schedule:**
The Working Group should begin meeting by September 2014, with the intention of developing a list of proposed changes, priorities, and a time-line by mid-year 2015, at which time the Working Group will have no additional tasks unless further agreed by the Working Group members based on experience in 2015. While this time frame precedes a decision in Phases 2 and 3 of R. 13-09-011, discussion to date shows consensus on a number of issues. Since

solutions will take time, in order to allow increased integration of DR into CAISO markets sooner rather than later, the group should start working before any December 2014 decision.

6. **How results will be used:**
The results should be used to inform future CAISO stakeholder processes addressing demand response integration issues and possibly to inform a future review of possible changes to Rule 24/32 or RA requirements. Proposed demand response program design changes will inform the IOUs' 2017-2019 demand response applications.

7. **Prioritization:**
The Working Group will establish its own priorities for reviewing the areas for possible change already identified and developing new ones. Based on work to date, the following areas are good initial candidates for possible change and additional items will be considered by the group. To the extent that some issues involve policy considerations or policy changes, the Working Group will identify and prioritize but not address such issues:

a. automating CAISO resource registration and updates (includes bulk-loading registrations and functionality to update existing PDRs)
b. reconsidering the requirement that each resource must contain customers from a unique LSE
c. reconsidering of the requirement for LSE approval for utility and non-utility DRPs to bid load of customers into CAISO markets
d. business systems automation for verifying that no load participates in more than one resource
e. creating functionality for changes to RDRR locations during the year, at least on a monthly basis, and proposals that qualifying capacity changes of RDRR be accounted for in RA showings per rules established in CPUC RA proceeding for CPUC-jurisdictional LSEs
f. creating of CAISO stakeholder process to consider adding functionality for constrained or discrete dispatch option for marginal dispatch of DR
g. automating support of baseline and performance requirements, e.g. for partial dispatch of PDR over monthly use limitations
h. implementation of statistical sampling rules
i. creating CAISO stakeholder process to address near real-time data requirements, including exploration of use of AMI local network, KYZ pulse output, and 3rd party systems; may involve review of 1-minute requirement
j. program dispatch automation
k. enhanced forecasting techniques and methodologies
l. tailored program offerings (one size does not fit all) and incentive structures
m. Consider way to reduce constraints imposed by the 100 kW minimum resource requirement by sub-LAP and LSE. Explore alternatives such as combining LSEs in a single registration or combining sub-LAPs if and where operationally acceptable. Also consider how to better integrate LCAs and SubLAPs.

Attachment 2: Telemetry Issue Paper

Supply DR Integration Working Group Telemetry	
Team Lead	Robert W. Anderson, Olivine
Group Members	Jennifer Chamberlin, Johnson Controls Steven DeBacker, PG&E Tomislav Galjanic, SCE Mona Tierney-Lloyd and Jaden Crawford, EnerNOC Wendell Miyaji, Comverge Eric Woychik Strategy Integration Ali Miremadi, CAISO Barbara Barkovich, CLECA

Introduction

This document contains the following issues, each in its own section:

- Easing Requirements for Energy-Only PDRs
- Review 1-minute requirement for PDR telemetry in those cases that telemetry is required
- Data Accuracy, including exploration of specific telemetry sources including KYZ pulse output, AMI local network, and 3rd party systems
- Review of requirement of 24/7 telemetry data for PDR
- Review Telemetry Data Point Requirements for PDRs

Note that while these items cannot be completely independent, the proposals are intended to stand alone. In particular, the first section proposes changes to the requirements for energy-only PDRs, while the following sections propose changes to the requirements whenever telemetry is required for PDRs.

Easing Requirements for Energy-Only PDRs

Issue Statement

Proxy Demand Resources (PDR) can participate in the CAISO's energy markets and in all of its ancillary services markets except regulation.[1] The CAISO requires real-time telemetry for resources providing any ancillary service and for resources in its energy markets that are 10 MW or greater.[2] This first issue **focuses exclusively on energy-only PDRs** that are not certified to provide ancillary services and that provide 10 MW or more of curtailment.

The telemetry requirement is as follows:

> To meet this requirement, resource owners must install "equipment and/or software that can interface with the CAISO's Energy Management System (EMS) to supply telemetered

[1] Details for PDR to provide spinning reserve are pending.
[2] CAISO's Telemetry BPM, Section 2.1, page 9.

real-time data. That Remote Intelligence Gateway (RIG) or equivalent will serve as the primary means for secure communications and direct control between the Generator's Generating Unit and the CAISO's EMS as a prerequisite for participation in any of the CAISO markets requiring real-time data. Participating Loads and Proxy Demand Resources are also subject to these requirements for telemetry of real-time data."[3]

Parties have raised concerns that CAISO's rules requiring telemetry for energy-only PDRs impose significant costs for participation in the CAISO markets. The metering and data collection/reporting requirements of wholesale markets around the country vary considerably, and in some cases are more or less stringent than the CAISO requirements[4]. It is not clear how the 10 MW threshhold was determined and whether that threshold should be determinative for distributed energy resources. However, a telemetry requirement creates a cost barrier for energy-only PDRs, which, like other distributed resources, are generally made up of an aggregation of locations, a significant difference when compared to large, central-station generation resources. PDR resources are distributed resources within a sub-LAP (load aggregation point), and therefore are geographically dispersed. The telemetry requirement for PDRs requires the collection of data from each of the locations that comprise the PDR registration to a central point, and that data to be relayed to the CAISO in real time through a RIG. The collection of data across multiple sites, relaying that information to a central collector, then relaying that information to the CAISO, is complex and costly.

Generation resources can fulfill the telemetry requirement through the addition of a remote intelligent gateway (RIG) to a facility. PDR resources need a RIG as well; but, in addition, PDR resources need a solution for real-time metering and data collection at all underlying locations within a registration. In addition, aggregated PDR resources need a solution for processing, aggregating, calculating a real-time baseline, and sending the telemetry points required in Section 7.1 of the CAISO BPM for Direct Telemetry. The cost to develop and integrate such solutions with existing platforms and the cost to maintain them can be prohibitive. Note that removing the real-time baseline calculation as required by the BPM does not dramatically impact the costs to develop, integrate, and maintain such a solution, primarily because the major costs are in retrieving telemetry from the locations (i.e., one of scale).

The cost-prohibitive nature of the telemetry requirement has already resulted in larger potential resources being artificially split into smaller sub-10 MW resources with identical bid strategies to avoid telemetry costs. It is unclear whether it is better for CAISO to have a larger resource without telemetry, or many smaller resources without telemetry. This solution of splitting up resources is suitable in some instances; however, in many it is not. Smaller resources carry with them larger potential variations in performance. Aggregation allows the under-performance of some resources to be balanced by over-performance of others. As aggregations become smaller and smaller, the diversity across the resource diminishes in terms of types of customers and size. Therefore, smaller resources are more difficult to manage from a risk profile perspective, thereby increasing the management effort of the resource and the potential for poor performance. For this

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[3] Id.

[4] See http://www.isorto.org/ircreportsandfilings/2013-north-american-demand-response-characteristics-available for annual reports comparing wholesale demand response programs across North America.

reason, avoiding a telemetry requirement by keeping the resource sizes small is not, in itself, a solution due to the increased performance risk.

Proposed Solutions

The parties are concerned that the telemetry requirement for energy-only PDRs over 10 MW imposes a cost that inhibits participation in CAISO energy markets by demand response resources. These costs act as a barrier to accomplishing the goal of the CPUC and other policy-makers to integrate supply-side DR, including existing DR aggregations, into the CAISO's markets.
Instead of making a unique proposal for changes to reduce these barriers, the parties are making a list of proposals in priority order.

- Proposal #1 would provide the greatest degree of simplification to current requirements for energy-only PDRs and cause the greatest reduction in current barriers caused by telemetry requirements.

- Proposal #2 would achieve less simplification and thus a smaller reduction in current barriers, but would still help facilitate the participation of PDR in the energy markets.

- Proposal #3 would provide still less simplification and a smaller reduction in barriers, but would facilitate somewhat more PDR participation in energy markets than under current requirements.

Note that these proposals address telemetry for energy-only PDR, not meter data supplied to the CAISO; it is expected that meter data will continue to be required for all PDRs providing any service to the wholesale market.

Proposal #1

PDRs that are not certified to provide ancillary services would be exempt from all telemetry requirements. In other words, eliminate the telemetry requirement for PDRs providing only energy, regardless of size.

Proposal #2

PDRs that are not certified to provide ancillary services would be exempt from all telemetry requirements as long as the PDR is smaller than 50 MW. In other words, raise the 10 MW energy-only telemetry requirement for PDRs to 50 MW.

Proposal #3

PDRs that are not certified to provide ancillary services would be required to provide telemetry only if either:

- The PDR consists of a single location and is greater than or equal to 10 MW; or,
- The PDR is made up of multiple locations and is greater than or equal to 50 MW.

In other words, the existing 10 MW requirement stands, unless the PDR is made up of multiple locations, in which case the requirement is raised to 50 MW.
Note that the rationale for choosing a number of locations as a qualifying condition is based on an expectation that the CAISO will not provide an exception to its existing telemetry requirements purely on the basis of the nature of the resource, given its preference for technology-neutral policies. That is, the fact that demand response is inherently different from conventional

generation as it is provided by load and is inherently dispersed, may be considered an insufficient justification. As such, choosing a number of locations as a threshold has relevance because the cost of providing telemetry is greater for distributed aggregations of PDRs.

Recommended Policy Change as it relates to Telemetry for Energy-Only PDRs

A change to the BPM for Direct Telemetry would need to be made; the specific edits will depend on the specific proposal.

In accordance with proposal #1, the following sentence would be added as a new paragraph to the end of section 6.1 of the BPM:

> *A PDR that provides energy only is exempt from the telemetry requirement.*

In accordance with proposal #2, the following sentence would be added as a new paragraph to the end of section 6.1 of the BPM:

> *A PDR that provides energy only and is under 50 MW is exempt from the telemetry requirement.*

In accordance with proposal #3, the following sentence would be added as a new paragraph to the end of section 6.1 of the BPM:

> *A PDR that provides energy only, is made up of multiple locations, and is under 50 MW is exempt from the telemetry requirement.*

Review 1-minute Telemetry Requirement for All PDRs

Issue Statement

Under the current CAISO Direct Telemetry BPM, PDRs have a 1-minute telemetry requirement if they are providing ancillary services or are providing energy-only if the resource is greater than 10 MW.[5] Among the ancillary services, PDRs can provide non-spinning reserves. It is expected that tariff and BPM changes are imminent to support spinning reserves.[6]
A telemetry requirement is a significant expense, and affects the economics of a demand resource's participation in the wholesale market, resulting in a barrier to participation for PDR. Telemetry requirements vary in wholesale markets; it is not universally required for demand resources that provide reserves. The CAISO states that it requires PDRs providing ancillary services to have telemetry because of the WECC BAL-002 requirement that the CAISO must know what its operating reserves are at all times.

This requirement is not a NERC requirement that applies to all other ISOs; it is currently only applicable in WECC. However, NERC is considering creating more uniform national standards and the result of that process is unknown at this time.

In addition to the cost of telemetry per se, the 1-minute requirement imposes additional costs, and creates a second barrier. Generally, utility meters cannot provide 1-minute data because they are not programmed to read at 1-minute intervals. Reprogramming meters to provide such data and storing the data would be very costly. The utility meters record 15-minute interval data for commercial and industrial customers and hourly or 15-minute data for residential customers.[7] Third parties can obtain these data on a 24-hour lagged basis through the IOUs' Customer Data Access (CDA) systems at the aforementioned intervals that are recorded by the utilities. These data will not be available in 1-minute increments.

Therefore, the issue arises as to whether there is another source of data other than utility meters that can collect data in smaller intervals for provision to the CAISO. Potential alternative data sources for entities seeking to bring retail demand resources into the CAISO's markets are home area network (HAN) devices or requests to the utilities to install devices on customer meters[8], such as KYZ pulse devices, to read customer usage in smaller intervals. These sources could provide operational and compliance data to the CAISO, to let it know that resources are responding, while revenue quality utility meter data (RQMD) would continue to be used for settlement purposes. Existing KYZ pulse devices currently record 5-minute interval data and can

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[5] The previous proposals in this paper, if adopted, would eliminate telemetry requirements for energy-only PDRs under certain conditions.

[6] The CAISO has not proposed a timetable for permitting PDRs to provide regulation service so this is not addressed within this document.

[7] PG&E will have 15-minute data for 100,000 residential customers by the end of 2016 and this can be expanded significantly with statistical sampling.

[8] In the case of KYZ pulse devices or, by extension, any device that is directly connected to the utility meter, the customer's Meter Service Provider (MSP) installs the device on behalf of the aggregator with the aggregator paying for installation and owning the device. The MSP is generally the utility distribution company.

be re-programmed to read at 1-minute intervals. Reprogramming would require site visits to each customer location and thus add significant expense for the aggregator.

There will be an additional cost to record usage information in smaller increments. This will require more frequent collection of data due to device storage limitations and will require investment in significantly greater storage capacity for the collected data.

There will be further costs and challenges associated with aggregating each location's 1-minute interval data to the resource registration level and communicating the aggregated PDR reading to the CAISO in real time. This process would take a significant amount of dedicated resources for systems and programming, especially since PDR registrations are finite and could change as a normal course of business.

Thus, the first issue is whether the CAISO would accept 5-minute data, rather than 1-minute data, in order to mitigate the cost impacts on entities aggregating load to participate in the CAISO's markets. In the next sections, we discuss other issues such as data accuracy requirements for such alternative data sources and data latency.

We note that other ISO/RTOs have varying data requirements. PJM requires 1-minute interval data for purposes of providing synchronized reserves 2 days after dispatch. The data, 2 days later, are also raw data that have not been Validated, Edited, and Estimated (VEE'd). For purposes of providing energy, PJM requires hourly data 60 days after the event. NYISO requires hourly data 75 days after the event.

ISO-NE had a similar requirement to that of the CAISO, i.e. that real-time data be transmitted from DR resources with a requirement that the data be accurate; because of the risk associated with "raw data" and other design features of the ISO-NE market, demand resource participation has fallen.

Proposed Solution

The parties propose that the 1-minute telemetry requirement for PDRs be relaxed to the longest interval that is acceptable to the CAISO, but at a minimum, to 5 minutes. The proposal:

- When the PDR is required to provide telemetry – including for energy and non-spinning reserves – and the PDR is made up of multiple locations:
    - the telemetry requirement would be expanded from 1-minute to 5-minutes.
    - the raw data utilized for telemetry will be an average over a 5-minute interval. Note that meeting the +/-2% accuracy requirement is covered in the next section of this document.
    - The per-location 5-minute average reads that make up the resource-level telemetry will be time-aligned within any PDR resource to within a +/-30 second time accuracy compared to a resource-specific synchronization time. If and when a location's telemetry source drifts outside of this band, it will be the resource owner's responsibility to synchronize the telemetry source.
    - The resource-level telemetry points will be available within the remote intelligent gateway (RIG) for the CAISO's 4-second poll with no more than a 1-minute latency.

The following diagram shows the timing and latencies of the telemetry data under this proposal:

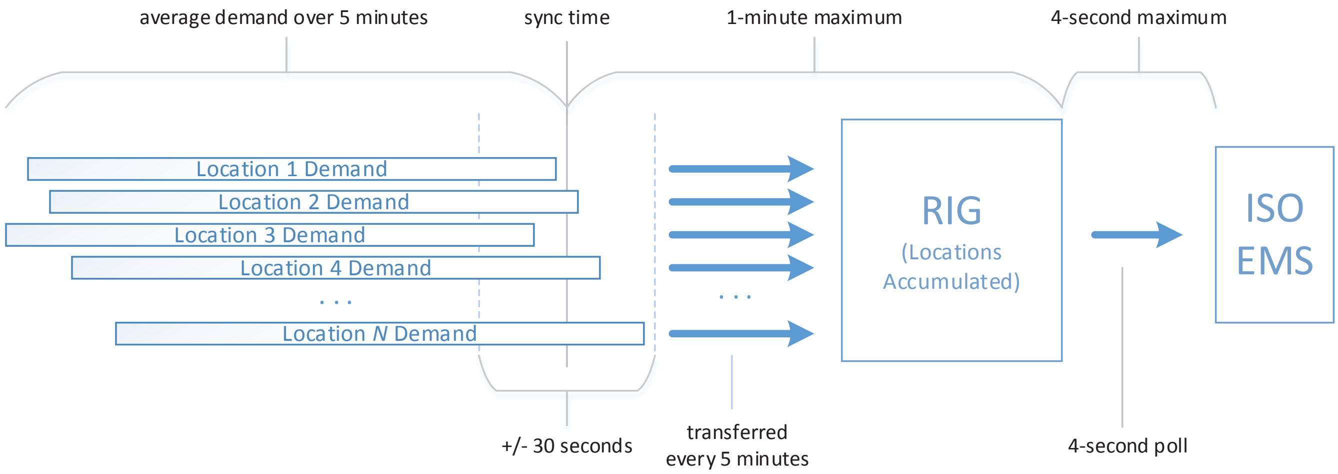

Figure 1: Timing for 5-minute telemetry proposal[9]

Note that the earliest start time for the combined 5-minute intervals provided to the CAISO will be up 6 ½ minutes in the past. This is the sum of the 5-minute interval, the worst case of -30 seconds of clock synchronization error, and the 1-minute maximum from the synchronization time to the RIG. With this process repeating every 5 minutes, immediately preceding an updated telemetry value to the CAISO, the earliest start time for the current combined 5-minute interval will be 11 ½ minutes.

Recommended Policy Changes

A change to the BPM for Direct Telemetry would need to be made. It is proposed that:

a) The following text would be made the complete text of 6.2.2:

The provisions of Section 6.2.1 shall apply to PDR telemetry, except that as an option, the resource telemetry requirement may be expanded to either 1-minute or 5-minutes. In this case, raw data utilized for telemetry will be an averaged over that defined interval. The per-location 5-minute average reads that make up the resource-level telemetry will be time-aligned within any PDR resource to within a +/-30 second time accuracy compared to a resource-specific synchronization time. If and when a location's telemetry source drifts outside of this band, it will be the resource owner's responsibility to synchronize the telemetry source. In all cases, the resource-level telemetry points will be available within the remote intelligent gateway (RIG) for the CAISO's 4-second poll with no more than a 1-minute latency.

b) Add section *6.2.3 PDR Reading Requirements*:
The provisions in this document shall apply to PDR telemetry, except that all references to "real time updated value and not averaged over time" should be taken as "real time updated value or average reading over the PDR timing interval".

[9] This figure is Copyright 2014-2015, Olivine, Inc. It may be reproduced with attribution.

Data Accuracy

Issue Statement

Section 5.5, Data Validation and Confidentiality of the Direct Telemetry BPM states the requirement for telemetry accuracy:

> All telemetry data reported via the RIG must be within +/-2% of the true value.
>
> The CAISO or its designee may inspect the resource owner's RIG and related facilities to verify the accuracy and validity of all data telemetry to the CAISO. The CAISO reserves the right to periodically audit and re-verify the accuracy and validity of all telemetry data. In addition, the CAISO's verification activities will be coordinated with the resource owner at least 24 hours in advance.
>
> . . .
>
> All data telemetry provided through the resource owner's RIG shall be tested by the resource owner or resource owner's representative for accuracy and validity on a periodic basis as necessary to assure that the accuracy requirements are maintained. The best practice is to test all resource data annually for accuracy.

For actual "direct telemetry" – as is the case for conventional generators – the +/-2% accuracy requirement is mainly one of ensuring adequate equipment (i.e., metering, current transformers, etc.) that is capable of providing an instantaneous read within +/-2% of true power. The measurements from such equipment are provided directly to an on-site RIG from which it is collected by the CAISO.

When applying this to aggregations of locations within a PDR, there are various concerns:

- When measurements are performed using a KYZ pulse meter, it may be that suitable accuracy can only be achieved during certain times of the day. This is because the accuracy of this technology within any interval of time is related to the number of pulses generated during that time. So, for example, a specific location may be calibrated to provide KYZ pulses that meet the accuracy requirement at intervals shorter than the utility metering interval, but only during periods of sufficient load. It may be less accurate when a PDR is dispatched, because the KYZ pulse meter produces fewer pulse at lower loads[10]. Thus, accuracy must be determined under different load levels.
- When measurements are performed using either instantaneous reads or average interval reads that are inherently accurate across the interval, suitable accuracy can be achieved as long as a sufficient number of locations are correctly reporting data.
- Unlike meter data provided for billing and settlements, there is no opportunity to perform Validation, Editing, and Estimation (VEE) on real-time telemetry. As a result, the telemetry data are "raw" and may at times include gaps and spikes that would normally be corrected in a normal VEE process. This is the same problem that conventional generators have (i.e., that raw data is provided), but it is made more challenging because of the number of locations that are combined to produce telemetry for PDR.

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[10] The KYZ technology has an inherent dead band within which the meter will not produce any pulse counts. This dead band is more of a concern as the interval period becomes shorter.

It is the belief of the parties that the telemetry accuracy requirement must be resolved in a cost-effective manner, or it may inhibit the ability of PDR to participate in the ancillary services markets and possibly the energy markets at a scale large enough to support a valid business model.

Proposed Solution

The parties would like the CAISO to accept the following methodology for meeting the requirement:

- The resource owner will test at installation time that individual location-installed telemetry solutions are within +/-2% accuracy compared against test intervals using the billing meter or using an instantaneous energy measurement device separate from the telemetry solution that is within +/- 2% accuracy, noting that in the case of comparing against billing intervals, an entire billing interval will be used for comparison.
- For KYZ and any technology for which the accuracy may be dependent on interval and load level, the resource owner will test data accuracy under different conditions, including normal load conditions and during the period when the PDR is dispatched. It will be important to demonstrate that the data meet accuracy requirements at periods of low load as in a dispatch situation.
- The resource owner will produce an annual telemetry report (see below for an example specific to KYZ metering) that demonstrates accuracy compliance. This report will also include reports on PDR location "uptime" to validate accuracy for non-KYZ metering.
- The CAISO is asked to acknowledge and/or make an exception explicitly allowing that telemetry data is "raw" and may include short-term anomalies. It will continue to be the resource owner's responsibility to correct any persistent issues.

The resource owner will be responsible for ensuring that the +/-2% accuracy will be met during periods of market activity (i.e., when bids are submitted). This would specifically allow KYZ metering that is calibrated for periods where load curtailment would be available to the market.

Example PDR Telemetry Accuracy Test Methodology for KYZ and Like Technologies

Once every year, resource owners of PDRs comprised of multiple locations (aggregated PDRs) must perform a comparison of aggregated telemetry data and aggregated utility revenue quality meter data (RQMD) corresponding to the PDR locations. The resource owner may choose the date for this test; however, it must be a day that demonstrates the range of possible telemetry values to ensure accuracy in low load situations. The specific hours for the comparison will be either the entire 24-hour period or, if the underlying locations are never available during certain hours, only those hours during which the overall PDR is to be available to the market.

If the PDR data is determined to be accurate to within 2 percent of utility data, the PDR will be deemed compliant with respect to CAISO telemetry data accuracy requirements. The results of this test will be available to the CAISO on request. This document proposes one such accuracy test and proposes that it be accepted as a valid methodology by the CAISO, noting that alternative accuracy tests may be accepted by the CAISO in the cases where there is an equivalent or more appropriate solution.

The PDR operator will collect 24 hours of PDR telemetry data, and will also obtain RQMD data for each location aggregated within the PDR for the same 24-hour period. These data must represent interval demand that occurred no more than 12 months prior to the date of the test. The comparison will take into account the correct conversions from or to demand and energy as appropriate. The methodology does not require a particular unit of measure.

Once PDR and Utility data are obtained, the utility data for all locations within the PDR must be summed by interval to create an aggregated value for each interval. For the avoidance of doubt, both the individual utility data and the aggregated data must be included in the accuracy report. In addition to aggregating utility data, the PDR telemetry data must be converted to the same interval as the utility data before the accuracy of the PDR data can be determined. This conversion must take into account the correct calculation based on the unit type (i.e., averages for demand, sum for energy). Once complete, there will one PDR telemetry interval for each of the RQMD intervals. For 1-hour RQMD, there would be 12 intervals, for 15-minute RQMD 96 intervals, etc. With comparable data, the accuracy of the PDR data can be determined as the relative root-mean-square error (RRMSE) using the following methodology:

The RMSE is calculated by first determining the square of the PDR interval data error (the squared error, or SE) for each interval. This is done by subtracting the value of the utility data in a given interval from the value of the PDR data in the same interval, then squaring the derived value. Once this is done, the mean-squared error (MSE) is derived by dividing the sum of the SE values by the number of intervals. The RMSE is derived by calculating the square-root of the MSE. The RMSE calculation is represented by the following formula:

$$RMSE = \sqrt{\frac{\sum_{t=1}^{N}\left(X_{1,t} - X_{2,t}\right)^2}{N}}$$

Where:

$X_{1,t}$ = PDR kW in interval, t
$X_{2,t}$ = Utility kW in interval, t
N = the number of intervals

The RRMSE is calculated by dividing the RMSE by the mean kW of the number of utility intervals and multiplying the derived value by 100, as represented by the following formula:

$$RRMSE = \frac{RMSE}{\bar{Y}} X\ 100$$

Where:

$\bar{Y}$ = Mean of the utility kW values

The RRMSE is expressed as a percentage, and indicates the variability of PDR data compared to utility data in the data set. By deeming the utility data to be correct in each interval, the terms “variability” and “accuracy” become interchangeable. Therefore, it can be said that an RRMSE of 2% or less indicates that PDR data is accurate to within +/-2% of utility data.

Review 24 x 7 Telemetry Requirement for PDRs

Issue Statement

Resources that provide telemetry to the CAISO have the requirement to provide valid telemetry around the clock, every day of the week.

Realistically, whether or not the resource owner has so-called “24 x 7” operations to respond to issues that arise, in many cases with DR aggregations, there are no personnel available at customer locations to resolve such issues. Considering the potential scale of PDRs, the cost to ensure telemetry at all times is significant.

Proposed Solution

The proposal is to ease this requirement such that, in the cases where telemetry is otherwise required for a PDR resource, it only must be provided during a window of time that encompasses when the resource is in a *dispatchable* state. This state would be defined as any time the resource has the potential for energy dispatch, e.g. during award hours related to a day-ahead bid and during any hours covered by a real-time bid, including both energy and ancillary services bids. To ensure that PDR real-time baseline logic is computed correctly, this window of time would include the hour leading up to the dispatchable period and terminate one hour after the end of that period.

There are two logical implications of this proposal:

- Telemetry outages outside of the window would not require outage scheduling;
- Alarms surfaced at the CAISO outside of the window would not trigger operations calls to the telemetry service provider; and,
- The accuracy requirements for telemetry would not be enforced outside of the window.

Note that this proposal specifically suggests that telemetry would not be available for exceptional dispatch unless the resource is already in a dispatchable state.

Recommended Policy Changes

While the 24 x 7 requirement is not explicitly stated, it can be inferred from other language in the document. A change to the BPM for Direct Telemetry would need to be made to remove any ambiguity. It is proposed that following paragraph be added to section 6.2.2:

RIGs providing telemetry for PDRs must provide valid data points only during the time that the PDR is in a dispatchable state, including one hour leading up to and one hour after that state. Dispatchable is defined as any time the resource has the potential for energy dispatch, specifically during day-ahead award hours and real-time energy bids.

Review Telemetry Data Point Requirements for PDRs

Issue Statement

Sections 7 and 14 of the Direct Telemetry BPM (Telemetry Data Points List and PDR Point Requirements, respectively) both specify telemetry data points required of PDRs. Since there is no language in the BPM explaining the relationship between the requirements in Section 7 and those in Section 14, it is uncertain to the parties whether the points in Section 14 are PDR-specific substitutes for similar point requirements contained in Section 7, whether they are the only points required of PDRs, or whether they are points that must be provided by PDRs in addition to all of the points required of PDRs within Section 7.

Section 7.1 Point Matrix states that Section 17 Real-time Point Definitions has the detailed definitions for the point matrix. Contrary to this statement, however, Pseudo Gen MW, Bias Load MW, and Aggregated Gross MW are listed as required PDR telemetry points in Section 7.1, but are not defined in Section 17. Similarly Real Load MW, PDR Unit Connectivity Status, and PDR Unit Ready to Start and Start Status are listed along with Pseudo Gen MW and Bias Load MW in Section 14.1, but are not listed as required telemetry points in Section 7.1, nor are they defined in Section 17.

Each of the values discussed in Section 17.1—Analog Values and Section 17.2—Digital Values state with specificity: the value to be defined, the definition of the value, the operational purpose of the value, and acceptable methods for providing the value. This level of specificity is not provided for any of the values in Section 14.1. As a result it is not clear how or even if the values in Section 14.1 relate to the values in Section 7.

For example: Real Load MW in Section 14.1.1 appears to be a PDR specific substitute for the term, “Gross MW” as defined in Section 17.1.1 Unit Gross MW. But it may also apply to Aggregated Gross MW. This makes it unclear whether Aggregated PDRs must provide unit Real Load MW for each location within an aggregation in addition to providing aggregated Real Load MW.

Proposed Solution

Changes to the BPM for Direct Telemetry would need to be made to provide clarity. It is proposed that:

a) The following point matrix would replace the point matrix in Section 7.1

Analogs	AGC	Spinning Reserve	Non-Spinning Reserve	QF Conversion	Energy Only	PDR	Solar	Wind	Solar/Wind less than 10MW
Unit Gross MW	X	X	X	X Note9	X		X	X	
Unit Net MW	X Note1	X Note1	X Note1	X Note1 & 9	X Note1		XNote1		
Unit Point of delivery MW	X	X	X	X	X		X	X	X
Unit Auxiliary MW	X Note2	X Note2	X Note2	X Note2 & 9	X Note2		XNote1		
Pseudo Gen MW						X			
Real Load MW						X Note 10			
Bias Load MW						X			
Unit Generator Terminal Voltage	X	X	X	X	X		X	X	XNote12
Unit Gross MVAR	X	X	X	XNote9	X		X	X	
Unit Net MVAR	X Note3	X Note3	X Note3	X Note3 & 9	X Note3		XNote3		
Point of delivery MVAR	X	X	X	X	X		X	X	X
Auxiliary MVAR	X Note4	X Note4	X Note4	X Note4 & 9	X Note4		XNote3		
Capacitor Bank VAR							X	X	
High\Line Side Bank MW	X Note5	X Note5	X Note5	X Note5	X Note5		X	X	
High\Line Side Bank MVAR	X Note5	X Note5	X Note5	X Note5	X Note5		X	X	
High\Line Side Bank Voltage	X Note5	X Note5	X Note5	X Note5	X Note5		X	X	
Aggregated Gross MW	X Note6	X Note6	X Note6	X Note9	X Note6				
Aggregated Net MW	X Note6	X Note6	X Note6	X Note9	X Note6				
Aggregated Point of delivery MW	X Note6	X Note6	X Note6	X Note6	X Note6				
Aggregated Gross MVAR	X Note6	X Note6	X Note6	X Note6	X Note6				
Resource ID Setpoint Feedback	X								
RIG Heart Beat	X	X	X	X	X	X	X	X	X

Analogs	AGC	Spinning Reserve	Non-Spinning Reserve	QF Conversion	Energy Only	PDR	Solar	Wind	Solar/Wind Less than 10MW
Aggregate\Unit Operating High Limit	X								

Aggregate\Unit Operating Low Limit	X								
Wind Speed (Meter / Second)							X	X	X
Wind Direction (Degrees - Zero North 90CW)							X	X	X
Air Temperature (Degrees Celsius)							X	X	X
Barometric Pressure (HPA)							X	X	X
Back Panel Temperature (Degree C)							X Note11		X Note11
Plane Of Array Irradiance Watts\Meter Sq.							X Note11		X Note11
Global Horizontal Irradiance Watts\Meter Sq.							X Note11		X Note11
Direct Irradiance Watts\Meter Sq.							X Note11		X Note11
Diffused Plane Of Array Irradiance Watts\Meter Sq.							X Note11		X Note11
Diffused Global Horizontal Irradiance Watts\Meter Sq.							X Note11		X Note11
Reference Cell (MW @ .001 resolution)							X Note11		X Note11

Digitals	AGC	Spinning Reserve	Non-Spinning Reserve	QF Conversion	Energy Only	PDR	Solar	Wind	Solar/Wind Less Than 10MW
Unit\Resource Connect	X	X	X	X	X		X	X	X
PDR Unit/Resource Connect						X			
Power System Stabilizer	X Note 7	X Note 7	X Note 7	X Note 7	X Note 7				
Automatic Voltage Regulator	X Note 7	X Note 7	X Note 7	X Note 7	X Note 7		X Note 7		
Capacitor Bank Breakers							X	X	
Unit Low Side Breaker	X	X	X	X	X		X	X	XNote13
Related Unit Breakers	X	X	X	X	X		X	X	
Related Unit MOD's Disconnects	X	X	X	X	X		X	X	
Data Port Alarms	X	X	X	X	X	X	X	X	X
Switchyard Line Breakers (if Generator Owned)	X	X	X	X	X		X	X	
Switchyard Line MOD (if Generator Owned)	X	X	X	X	X		X	X	
Aggregated\Unit Connected	X Note6	X Note6	X Note6	X Note6	X Note6				
Aggregated\Unit Authority Switch	X Note8								
Aggregated\Unit Control Switch	X Note8								
Aggregated\Unit Automatic Generation Control	X Note8								
Aggregated\Unit Ready To Start			X						
PDR Unit/Resource Ready To Start						X			
Aggregated\Unit Start PDR Unit/Resource Start			X			 X			

b) The following text would be made the complete text of Section 14.

Proxy Demand Resource (PDR)

Proxy Demand Resources shall follow the direct telemetry standards defined in this BPM. Refer to Section 6.2.2 for telemetry timing requirements.

PDR Point Requirements

Real Load MW

Definition:

This quantity is defined as the total real-time load or the power consumed by the resource; it can be directly measured or calculated. For single unit resources, this is the quantity of load or power being consumed by that unit. For aggregated resources, this is a calculation of the sum of the individual units within the resource.

Purpose:

The Real Load MW data point is used to establish a baseline and calculate load reduction of a resource when the resource is dispatched.

Methods of providing this value:

This value can be provided directly from a field device, such as a revenue meter, or indirectly by interfacing to a PDR EMS. It can also be derived by statistical sampling a resource's underlying load. A method for calculating load is not valid unless approved by a CAISO RIG Engineer.

PDR Unit Connectivity Status (PDR UCON)

Definition:

The PDR UCON status is an indicator required for the setting of Bias Load

Purpose:

THE PDR UCON value is used to trigger calculation of Bias Load and set PDR ready to Start and Start Status

Methods of providing this value:

The PDR UCON can be manually set by an operator or programmed to change status based on an ADS Dispatch

Bias Load

Definition:

Bias Load is a calculated value that stores the initial Real Load MW value of a resource when the PDR unit connectivity status (UCON) is initially set to ON (HIGH).

Purpose:

The Bias Load is used to establish a resource's baseline load for the purpose of calculating Pseudo Generation MW.

Methods of providing this value:

The Bias Load calculation can be performed within a control system, EMS, or RIG.

PDR Ready to Start and Start Status

Definition:

The PDR Ready to Start status shows whether the resource is in a ten minute ready to start condition. The PDR Ready to Start and Start status are required only if a PDR is participating in the Non-Spinning Reserve market. The Ready to Start status should be set to ON (HIGH) if the resource has been awarded Non-Spinning Reserve by the market and is available for dispatches.

The PDR Start status indicates whether the PDR is responding to ADS dispatch.

Purpose:

The Bias Load is used to establish a resource's baseline load for the purpose of calculating Pseudo Generation MW. The Start status should be set to ON (HIGH) when the PDR UCON is ON (HIGH)

Methods of providing this value:

Both status points can be linked to the PDR UCON status.

Pseudo Generation MW

Definition:

The Pseudo Generation point is a calculated point derived by subtracting Real Load MW from Bias Load MW

Purpose:

The Pseudo Generation point allows the CAISO to model the PDR resource like a market Generating Unit in order to avoid a Western Electric Coordinating Council (WECC) violation of Reliability Standard BAL-002-WECC-2.

Methods of providing this value:
The pseudo generation calculation can be performed within a control system, EMS, or RIG.

Status and Pseudo Generation flow

The following chart is the sequence of the ADS signal when it changes for a PDR.

1A	**If ADS Dispatch Signal > Zero**	**1B**	**If ADS Dispatch Signal = Zero**
	Read to Start status = 0		Read to Start status = 1
	Start status = 1		Start status = 0
	PDR UCON = 1		PDR UCON = 0
	Real Load = Feeder Actual MW		Bias Load = 0
	Bias Load = Real Load		Pseudo Gen = 0
2A	Pseudo Gen = Bias Load - Real Load		Goto 1
	If ADS dispatch > 0 Then Next Else Goto 1B		
	Wait 60 seconds		
	Pseudo Gen = Bias Load - Real Load		
	Goto 2A		

(The CAISO ADS dispatches to non-Regulation resources)

The flow chart of the PDR status` and Pseudo Generation MW is shown on figure 8.

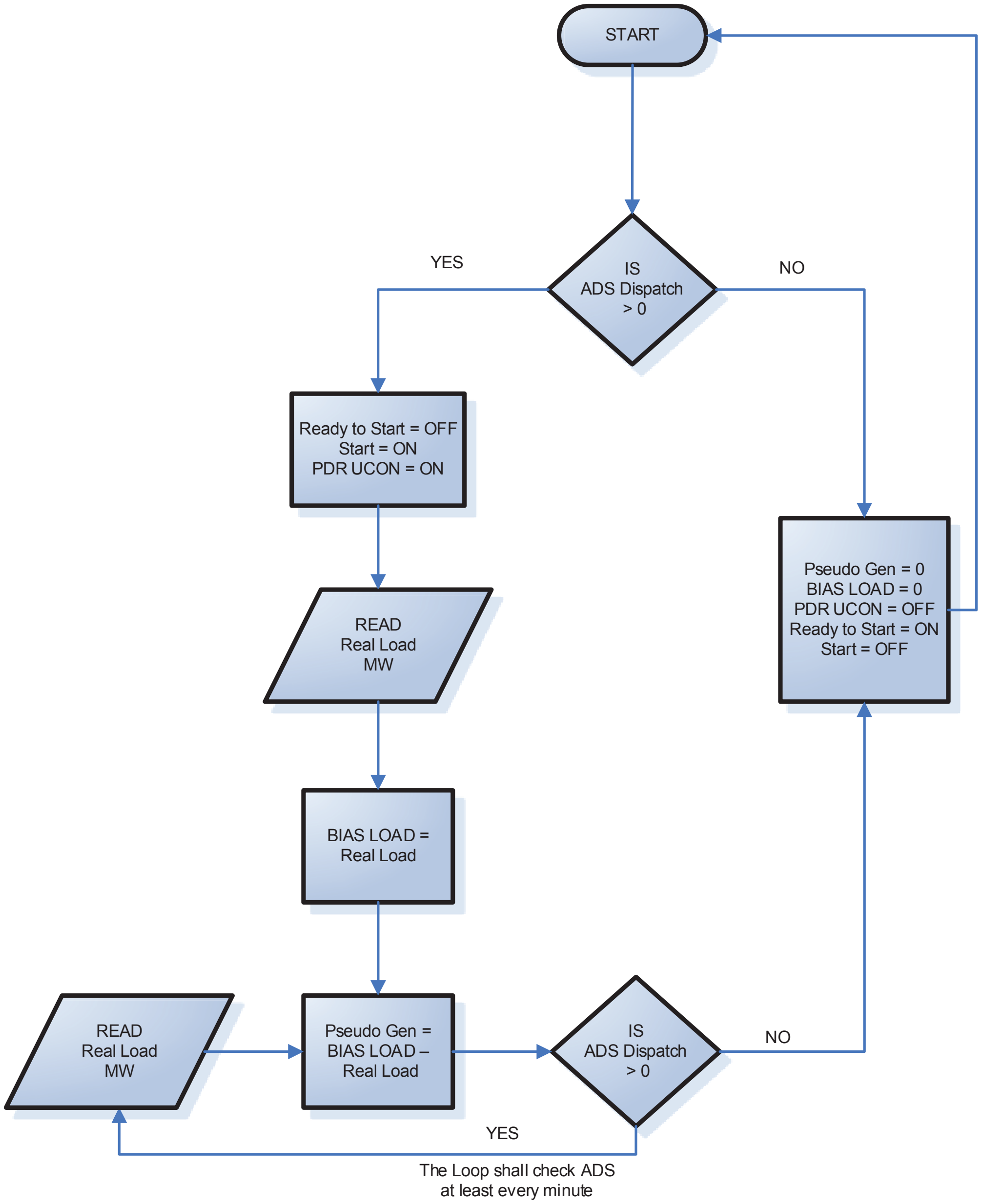

FIGURE 8 Calculations for Pseudo Generation

Attachment 3: Resource Requirement issue Paper

Supply DR Integration Working Group LSE/Resource Requirements	
Team Lead	Robert W. Anderson, Olivine
Group Members	Barbara Barkovich, CLECA Jennifer Chamberlin, Johnson Controls Tomislav Galjanic, SCE Melanie Gillette, EnerNOC John Goodin, CAISO

Introduction

This document contains the following issues, each in their own section:

- Revisit requirement for unique LSE per PDR
- Remove requirement for / or require DRP/LSE Agreement
- Ensures all LSEs are available within the DRS
- Correct calculation of Default Load Adjustment
- Revisit necessity of Default Load Adjustment

Support multiple LSEs per PDR/RDRR

Issue Statement

The CAISO requires that all locations within a single PDR/RDRR (proxy demand resource/reliability demand response resource) be served by the same load-serving entity (LSE). This is consistent with some interpretations of CPUC-ordered utility Rule 24/32. This requirement creates several challenges that impede participation of demand response in the wholesale market:

- Increases the difficulty in assembling sufficient resources to meet the minimum 100 kW PDR size requirement.
- Requires that utility retail program portfolios be split into multiple resources depending on the LSE, since direct access (DA) and community choice aggregation (CCA) customers can participate in utility retail programs and eventually bundled customers may participate in non-utility programs.
- May require significant numbers of locations to be omitted from a PDR, reducing wholesale market participation, if they do not meet the 100 kW PDR threshold by LSE even though they will be called upon to curtail when the PDR is dispatched.
- Raises management costs by increasing the number of resources in the market.

The unique LSE requirement primarily stems from the implementation of the Default Load Adjustment (DLA) – covered in a different issue – whereby adjustments to LSEs' load schedules are made based on the performance of PDRs. While an alternative design could have supported LSE-specific DLAs calculated from LSE-specific sub-aggregations of a PDR, the current implementation allows for only one DLA per PDR. We note that the issue of the DLA requirement is associated with the appeal of the repeal of FERC Order 745 and thus may not be resolvable at the present time. For this reason, the ability to combine LSEs within a PDR may be the most straightforward means of facilitating additional wholesale DR, given the CAISO's minimum resource size of 100 kW. We understand that combining LSEs within a PDR would require additional work by the CAISO to disaggregate the final load schedule adjustments and settlements.

Proposed Solution

The sub-group proposes that the CAISO enhance its systems by creating an alternative design to support multiple LSEs within a single PDR. This is the narrowest solution to the constraint imposed by the one-LSE requirement, although it may require CPUC action (see below). This could be done through an enhancement to the current demand response system (DRS) or as part of the new "DR Solution" at the CAISO. Other systems could support this alternative design through the following changes:

- Maintain the current requirement of one LSE per registration.
- Allow multiple active registrations within a single PDR (which may be supported with the new aggregated location (ALOC) application programming interface (API) under development.
- Continue to submit settlement quality meter data (SQMD) at the registration level, noting that in the case of parallel registrations (i.e. more than one LSE in a registration), the CAISO will need to perform the ultimate aggregation of SQMD to the resource level.
- Enhance downstream systems at the CAISO to perform LSE-specific DLA calculations while maintaining the resource-level settlement calculation.
- If necessary (i.e., if it is agreed that the LSEs have a right to this information), the demand response provider (DRP) would be required to share LSE-specific resource award information with each LSE with load impacted by that award; otherwise, eliminate the award notification requirement.

Since the one-LSE requirement is deemed by many to result from the Rule 24/32 CPUC requirements as long as the DLA exists, there may be a need for the CPUC to revise Rule 24/32 to clearly allow aggregation of LSEs in a PDR as proposed in this section.

There may be technical and or procedural implications at the ISO in implementing this solution; we need the ISO to weigh in on whether there are any such issues.

Initial CAISO Comment:
Proposed solution description:

- *Enhance downstream systems at the CAISO to perform LSE-specific DLA calculations while maintaining the resource-level settlement calculation.*
- The initial CAISO concern is that settlement, including uninstructed imbalance energy (UIE) and determination of DLA, is performed at a resource level, not at a registration level and that it would be a major undertaking to support this use case. An alternative suggestion from the CAISO is that the

DLA be assigned to one of the impacted LSEs and that that LSE then be paid by the other LSEs that make up the PDR. The only party – other than the CAISO – that has the information to calculate this while maintaining some semblance of confidentiality is the DRP in conjunction with its scheduling coordinator (SC). While this alternate solution is technically possible, the implications are wide-ranging and costly. Such a solution may deserve further discussion.

Alternatives Considered

Other alternatives are enumerated in other issues, the principal one being to eliminate the DLA altogether.

Recommended Policy Changes

Remove Requirement for/or Develop Pro-forma LSE/DRP Agreement

Issue Statement

The CAISO requires an agreement between the DRP and the LSE. This is stated explicitly in the Metering BPM, section 12.5.1. In addition, the PDR agreement between the ISO and the DRP states that DRPs will have any necessary agreements with customer LSEs before a DRP registers a PDR.
There is some uncertainty as to whether this agreement is required under Rule 24/32 due to the CPUC's limited jurisdiction over non-utility LSEs. Clarification should be sought from the CPUC. If this is the case, a legislative solution may be required to overcome the limitations this agreement imposes on signing up retail customers for wholesale DR.

Because of this requirement, LSEs are capable of withholding or delaying an agreement, blocking or delaying their customers from choosing a DRP with which to directly participate in the wholesale market. This is contrary to FERCs ruling in Order 719 that LSEs do not have that right and differs from customer participation in utility programs, which does not require LSE permission.
Note that this issue only applies to customers whose LSE is not the distribution utility. This is because Rule 24/32 requires that investor-owned utilities sign such agreements with DRPs.

It is not clear that non-IOU LSEs (i.e., Energy Service Providers or Community Choice Aggregators) expected to have this contractual requirement.
This is not a theoretical problem, but an issue that has come up several times, even given the small number of direct access customers that have attempted to participate in a PDR so far.

Proposed Solution(s)

The sub-group proposes one of the following three solutions to this issue. The best solution will need to be determined with a combination of CAISO, CPUC, and, perhaps, legislative support:

- Solution 1:
  - The CAISO eliminates the requirement from the metering business practice manual (BPM) and removes the language in the PDR agreement referring to a DRP/LSE agreement.
- Solution 2:
  - The CAISO eliminates the requirement from the metering BPM, but retains the language in the PDR agreement referring to a DRP/LSE agreement "if necessary".
  - The CPUC, perhaps with legislative action needed due to the CPUC's limited jurisdiction over ESPs, rules that such DRP/LSE agreements are not necessary.

- Solution 3:
    - The CPUC, again, perhaps with legislative action needed, defines pro-forma DRP/LSE agreements similar or identical to the agreements for a DRP with an IOU and requires LSEs to execute these with DRPs.
    - While not a complete solution, a requirement that a DRP agreement be deemed accepted if an LSE has not signed it within 10 days could help with the delay problem.

Alternatives Considered

Other alternatives are enumerated in other issues, the principal one being to eliminate the DLA altogether.

Recommended Policy Changes

Ensure all LSEs are available in the DRS

Issue Statement

Before a DRP can register a PDR for a direct access customer, the LSE must request to be added to the CAISO's Demand Response System (DRS). This additional step is an opportunity for the LSE to effectively block its customers from choosing a DRP, similar to the problem raised in the LSE/DRP Agreement issue.

Proposed Solution

The CAISO should either add all LSEs to the DRS or should allow DRPs to initiate the addition of LSEs before or at the time of new PDR creation by identifying an LSE that is not in the DRS.

Alternatives Considered

Other alternatives to reduce cost are enumerated in other issues, the principal one being to eliminate the DLA altogether.

Recommended Policy Changes

This may require additional policy change in terms of addendums to existing LSE/ISO agreements.

Initial CAISO Comment:
Proposed solution description
The CAISO should either add all LSEs to the DRS or should allow DRPs to initiate the addition of LSEs before or at the time of new PDR creation by identifying an LSE that is not in the DRS.

- The CAISO suggests that the solution should include a statement as to the process the CAISO would take once the DRP initiates the addition of an LSE not in the registration system. Currently, the CAISO has no authority to require an LSE to obtain access and participate in the review of registrations. Therefore, this solution suggests that the CAISO should act on the DRP's request for an LSE to be included. It does not cover the case where the LSE does not obtain access to the registration system or does not choose to participate in the review process. Alternatively, the CPUC could review its Rule 24/32 requirements to determine if it could direct DRPs to initiate the addition of LSEs whose customers are participating in a PDR with the DRP.
- It appears that the CAISO is concerned about who has "authority to require the LSE to obtain access and participate in review". The parties do not dispute this; however, FERC has ruled that LSEs cannot withhold permission for their customers to participate with 3rd party demand response providers. The parties assert that the CAISO does not need to require the LSE to obtain access and review, but simply to notice the LSE that it has the right to review,

and that to do so it must “obtain access and participate in review”. If the LSE does not assert that right then it will not have the opportunity to participate. This may require a change in a tariff or a BPM, but the CAISO has the authority to administer PDR and RDRR and to impose those rules on all relevant market participants.

Alternatives Considered

Other alternatives to reduce cost are enumerated in other issues, the principal one being to eliminate the DLA altogether.

- The CAISO points out that the DLA is not the only issue arising from an LSE not being in the DRS. The approval/review process would still require the LSE to be included in the DRS. Therefore, in addition to eliminating the DLA, it would be necessary to provide that the CAISO does not require LSE review of underlying locational information for registrations.

Correct the calculation of the DLA

Issue Statement

The current DLA calculations are being performed incorrectly, resulting in a larger DLA than appropriate.

The DLA is intended to adjust the load schedule of the LSE in the case that a PDR delivers energy at a price below the net-benefits test (NBT). The issue occurs under the following conditions:

- A PDR bids in to the day-ahead market. Note that it is not necessary that the price be bid at or above the NBT.
- The PDR receives an award at or above the NBT.
- The PDR delivers energy in excess of the award.
- One or more real-time interval prices are below the NBT.

In this case, the DLA should apply to the portion of the energy delivery that is paid below the NBT (i.e., the excess delivery in intervals priced below the NBT, not the amount awarded and priced in the day-ahead market); however, DLA calculations are including the entire delivered energy.

Proposed Solution

There are two possible solutions to this issue:

- In the case that the resource is not qualified for real-time, the DLA would not be applied if the day-ahead award cleared at or above the NBT. The rationale is that the resource is not responding to real-time at all, but is simply attempting to respond to a day-ahead award.
- Correct the calculation so that only the excess quantity is assigned to the DLA.

Alternatives Considered

Other alternatives are enumerated in other issues, the principal one being to eliminate the DLA altogether.

Recommended Policy Changes

The first option may require a tariff change; however, the second likely only requires a fix to the settlement calculation.

Eliminate the DLA

Issue Statement

The existence of the Default Load Adjustment (DLA) creates many challenges to the integration of utility programs and third party direct participation with the wholesale market. Eliminating the DLA could reduce costs by greatly simplifying one aspect of this integration and better align with broader energy policy objectives of the State. The DLA may have to be reconsidered, depending on the outcome of the legal review of Order 745. A stay is in effect pending that review, but a review of the DLA would be timely once the courts have ruled and FERC has responded.

Proposed Solution

Eliminate the DLA

Alternatives Considered

Recommended Policy Changes

TBD

Attachment 4: Baseline Issue Paper

Supply DR Integration Working Group NAESB Baselines – 6 January 2015	
Team Leads	Wendell Miyaji, Comverge, Steve De Backer (PG&E)
Group Members	Barbara Barkovich (Barkovich and Yap), Muir Davis (SCE), Tomislav Galjanic (SCE), Ali Miremadi (CAISO), Eric Woychik (Comverge), Mona Tierney-Lloyd (EnerNOC), Robert Anderson (Olivine), Melanie Gillette (EnerNOC)
Issue Title	Settlement Baseline Calculation
Issue Statement	Methodologies for forecasting and reporting Energy and Capacity Demand Response are not clearly defined nor in complete alignment for the CAISO and CPUC processes. The need is to use consistent DR Baselines for DR performance that capture the market value in CPUC and CAISO processes, both for energy and capacity, including existing products (e.g. ancillary services) and expected new products (e.g. ramping services). The NAESB Model Business Practices for Measurement & Verification of Demand Response Programs provides authoritative guidance on this Demand Response performance reporting. The CAISO Business Practice Manuals for Metering (section 12) and Telemetry (section 14) describe how Demand Response M&V is currently performed.
Proposed Solution	The subgroup is requesting CAISO additions to the existing Type I & Type II Custom Baseline capability for both Energy (DA/RT) and Operating Reserves that are currently supported. In addition, the subgroup is requesting that Maximum Baseload evaluation for PDR Capacity No Pay Dispatch Performance be added as well as Meter Generator Output.
Alternatives Considered	The subgroup considered the applicability of the baseline methodologies defined in the NAESB Measurement and Verification of Wholesale Electric Demand Response (WEQ 015)[11] as it relates to the CAISO Services deliverable via the Proxy Demand Resource product (PDR).[12] Specifically, two services were addressed: Energy (DA/RT) and Operating Reserve. The subgroup proposes changes to the CAISO tariff and Business Practice Manuals [BPM] to enhance Type I and Type II Custom Baselines for Energy (DA/RT) and Operating Reserves, to add Meter Generator Output for Energy (DA/RT) and Operating Reserves, as well as to allow Maximum Base Load Evaluation[13] for PDR Capacity No Pay Dispatch Performance.

[11] North American Energy Standards Board, WEQ Measurement and Verification of Wholesale Electricity Demand Response Business Practice Standards, WEQ – 015 Version 003, July 31, 2012.

[12] California ISO, Demand Response – proxy demand response, http://www.caiso.com/23bc/23bc873456980.html, page as of December 15, 2014.

[13] Maximum Base Load Evaluation is also referred to as Firm Service Level in some forums.

	NAESB WEQ 015 defines five methodologies for Demand Response performance evaluation[14]: - Maximum Base Load Evaluation (WEQ 015 – 1.16): A performance evaluation methodology based solely on the ability of a Demand Resource to maintain its electricity usage at or below a specified level during a Demand Response Event. - Meter Before/Meter After (WEQ 015 – 1.19): A performance evaluation methodology in which electricity Demand over a prescribed period of time prior to resource Deployment is compared to similar readings during the Sustained Response Period. - Baseline Type-I (Interval Meter) (WEQ 015– 1.22): A Baseline performance evaluation methodology based on historical meter data for a Demand Resource that may also include other parameters such as weather and calendar data. - Baseline Type-II (Non-Interval Meter) (WEQ 015 – 1.25): A Baseline performance evaluation methodology that uses statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the entire population. - Meter Generator Output (WEQ 015 – 1.28): A performance evaluation methodology in which the Demand Reduction Value is based on the output of a generator located behind the revenue meter for the Demand Resource.[15] WEQ 015 considers these performance evaluation types as applicable for both the Energy and Capacity Service types.[16] During discussions within the subgroup and in consultation with the CAISO representatives to the subgroup, it was determined that the CAISO Tariff and Business Practice Manuals currently allow Baseline Type I – Standard and Baseline Type II – Standard methodologies for both Energy (DA/RT)) and Non-Spinning Reserve services for Energy Service evaluation. By Standard, this means that the specification calculation algorithm is defined by the CAISO in the Business Practice Manual. For example, a Customer Baseline is defined in the Metering BPM,[17] Section 12.6.1. For this baseline, the ten most recent eligible days from the previous forty-five days are selected and the meter measurements are averaged on an interval by interval basis to

[14] NAESB, WEQ-015, p. 7. Additional requirements for each of these methodologies are specified in NAESB, WEQ-015, pages 19 to 25.
[15] NAESB, WEQ-015, p. 24 states that a "The Governing Documents shall specify Baseline calculations for Metering Generator Output."
[16] Ibid.
[17] CAISO, BPM for Metering, Version 9, February 3, 2014.

	derive the customer baseline. This would define a Baseline Type I – Standard. For some demand response resources, the Baseline Type I – Standard defined in CAISO Metering BPM 12.6.1 may not accurately represent the typical energy use. Two day types are defined as Weekday and Weekend/Holiday. As an example, a demand response resource may have very different use patterns if it is closed on Sunday and open on Saturday. In this case by averaging the 5 previous Saturdays and 5 previous Sundays, the baseline would underrepresent the typical energy use on Saturdays and over-represent the typical use on Sundays. WEQ 015 provides leeway for modifying a Baseline Type I methodology for Highly-Variable Loads in paragraph WEQ 015-1.24.1. As an example, in another ISO, PJM defined and implemented a procedure for a demand response resource to propose and have approved an alternate baseline.[18] PJM defined a "relative root mean square error" test to assess the accuracy of the PJM standard baseline for a demand response resource and allows for the request of use of the alternative baseline if it is demonstrated to be more accurate than the standard baseline. When alternate baselines are approved by PJM, the baselines are published and available for requested use by other demand response resources. The subgroup requests that provisions for custom baselines be made for the Baseline Type I performance evaluation methodology for Energy (DA/RT) and Operating Reserves. Baseline Type II – Standard is supported in the CAISO BPM for metering in section 12.8 and CAISO Tariff Section 10.1.7. As discussed previously, there is the potential that a standard baseline calculation algorithm may also not be sufficiently accurate for a demand response resource that settles based on statistical sampling of Energy usage data. Similar non-standard schedules may apply. For this reason, the subgroup also requests that provisions for custom baselines be made for the Baseline Type II performance evaluation methodology for Energy (DA/RT) and Operating Reserves. Meter Generator Output – Standard is not currently supported by the CAISO but is an important evaluation type for M&V of two critical use cases: 1) accurately metering controllable loads within a larger facility to filter out uncontrolled inter-day and intra-day variability, 2) accurately metering a dual use (i.e., "behind the meter") storage asset. Note that this standard requires the use of a baseline to determine the expected consumption in the absence of a market event. This issue was a topic of the CAISO Energy Storage Roadmap and will be critical for the Combined PDR/NGR model contemplated by the CAISO in its Stakeholder Catalog. The subgroup requests that this baseline type be added as an option for PDRs. With these additions, Energy Performance could be evaluated by both Standard and Custom baselines under the Type-I and Type-II methodologies or the Meter Generator Output method. Meter Before/Meter After and Maximum Base Load Evaluation while

[18] PJM, PJM Manual 11: Energy & Ancillary Services Market Operations, Revision 69, October 30, 2014, p. 121.

	considered valid for the Energy Service type by WEQ 015, are not being requested by the subgroup for CAISO PDR. These two methodologies do not attempt to directly determine the energy that would have been used in a particular time interval by the demand response resource. For PDR Capacity No Pay Dispatch Performance, the group proposes the addition of Maximum Base Load Evaluation to the current provision for Meter Before/Meter After. The CAISO BPM for Metering provides for Meter Before/Meter After.[19] This performance evaluation method demonstrates the reduction in load within 10 minutes. An alternate methodology for evaluating performance is Maximum Base Load Evaluation. The value of this methodology is that it enforces a cap of the capacity used by a resource during each measured interval of a demand response event. This approach can help the CAISO manage the total energy used by the demand response resources rather than manage reductions which may start at much higher levels.
Recommended BPM Changes	Update BPM for Metering Section 12 to support Type I & Type II Custom Baseline capability for both Energy (DA/RT) and Operating Reserves and Maximum Base Load Evaluation for PDR Capacity No Pay Dispatch Performance. .
Recommended Tariff Changes	Update CAISO Tariff to support Type I & Type II Custom Baseline and Direct Meter Generation for both Energy (DA/RT) and Operating Reserves and Maximum Base Load Evaluation for PDR Capacity No Pay Dispatch Performance.
Other Policy Dependency	

[19] CAISO, BPM for Metering, Version 9, February 3, 2014, pp. 90 – 91.

Attachment 5: Select Group of Telemetry Requirements from Other ISO/RTOs

The CAISO has provided the following information on some telemetry requirements from other ISO/RTOs.

MISO

MISO has two types of resources for DR: Type 1 and Type 2. Both are eligible to provide energy or Operating Reserves. For energy, Section 4.3 of BPM 26 states:

> **4.3 Qualifications to Provide Energy**
> Both types of DRRs are qualified to provide Energy to the market. However, a DRR-Type I is only capable of delivering two levels of output: either zero or its Targeted Demand Reduction. In contrast, a DRR-Type II can deliver varying levels of output spanning a continuum, ranging from zero to its maximum capability and is also capable of following MISO 5-minute Dispatch Instructions. Because a DRR-Type II is treated as if it were a generator, it must be capable of providing telemetered output data.

As seen above, Type 1 (similar to RDRR in California) is a discreet dispatch product and does not require telemetry. The telemetry scan rate for DRR Type 2 is 10 seconds. Unlike CAISO's RDRR product, DRR Type 1 can only self-schedule, which means it is not optimized in real time and it does not set the real time price.

ISONE

ISO New England, for Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, requires their Demand Designated Entities (DDE) to transmit in real-time, five-minute interval data (for all intervals in an operating day) from the DDE to ISO through the direct communication link between the DDE and the ISO.

NYISO

New York ISO (NYISO) does not have a program to allow DR to offer bids in real-time. They have delayed any work on integration of DR in real-time until there is clarity on compensation for DR (FERC Order 745). However, the current design for DR in RT will require telemetry and will consolidate the various DR programs into a model where the DR resource can participate in the energy, capacity and ancillary services markets for which they qualify the same way a traditional supplier does, not as separate DR programs.

NYISO does allow DR to participate in Operating Reserves. Full telemetry is required for any demand side resource providing Operating Reserves (spin or non-spin) and Regulation. Aggregations of smaller resources are permitted to meet the 1 MW offer requirement of any supply resource in NYISO's market. Energy and ancillary services are co-optimized, but DR resources do not receive an energy payment, only the reservation payment, even when converted to energy. DR resources may offer reserves in the day-ahead or real-time markets.

Sections 6.2.3 and 6.2.4 of the NYISO's ancillary services manual provides the detail. In addition, the NYISO has a CEII document that details the specific information that is communicated between NYISO and a DR Provider:

http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/ancserv.pdf

ERCOT

At ERCOT, load is able to participate in real-time energy market and may provide energy reserves at ERCOT's ancillary services markets. Telemetry Requirements are specified in Section 3A of "Requirements for Aggregate Load Resource Participation" document:

> A Qualified Scheduling Entity (QSE) representing a Load Resource is required to send Resource-level Real-Time telemetry to ERCOT every two seconds per Protocol Section 6.5.5.2, Operational Data Requirements; Nodal Operating Guide, Section 7, Telemetry and Communication, and the ERCOT Nodal ICCP Communication Handbook available on the ERCOT website. Telemetered data points are specific to the service being provided, and are listed in detail in Protocol Section 6.5.5.2.
>
> The relevant telemetry signals shall represent one of the following:
>
> - The sum of the Load of all Premises in the ALR, or
> - The sum of the Load of the Devices under control.

Attachment 6: Participants in Supply Integration Working Group

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Ali Miremadi, CAISO

Active Participants in Sub-groups:

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